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PB-285 924

Optimization of Design Specifications for Large Dry Cooling Systems

PFR Engineering Systems, Inc, Marina del Rey, CA

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, NC

Jul 78

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-78-152
2.
3. RECIPIENT'S ACCESSION NO. PB285924
4. TITLE AND SUBTITLE Optimization of Design Specifications for Large Dry Cooling Systems
5. REPORT DATE July 1978
6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Tzvi Rozenman, James M. Fake, and Joseph M. Pundyk
8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS

PFR Engineering Systems, Inc.
4676 Admiralty Way, Suite 832
Marina del Rey, California 90291

10. PROGRAM ELEMENT NO. EHE624A
11. CONTRACT/GRANT NO. 68-03-2215
12. SPONSORING AGENCY NAME AND ADDRESS

EPA, Office of Research and Development
Industrial Environmental Research Laboratory
Research Triangle Park, NC 27711

13. TYPE OF REPORT AND PERIOD COVERED Final; 6/75-6/78
14. SPONSORING AGENCY CODE EPA/600/13
15. SUPPLEMENTARY NOTES IERL-RTP project officer is Theodore G. Brna, Mail Drop 61, 919/541-2683.

16. ABSTRACT The report presents a methodology for optimizing design specifications of large, mechanical-draft, dry cooling systems. A multivariate, nonlinear, constrained optimization technique searches for the combination of design variables to determine the cooling system with the lowest annual cost. Rigorous formulations are used in calculating heat transfer and fluid flow. All thermal and mechanical design variables of the cooling system components are analyzed. Thermal variables include ambient air temperature, condenser terminal temperature difference, cooling range, and initial temperature difference. Module variables are tube length, number of rows and passes, and fan power. The methodology employs a computer program with major computational blocks written as subroutines. The program optimizes dry towers with either surface condensers or direct-contact jet condensers. Results of detailed parametric and sensitivity analyses are presented. The relationships of design variables, major components, site variables, and utility economic factors to incremental annual costs are examined for 1000 MWe fossil fuel plants at five U.S. sites. Results, presented in both graphs and tables, show that all design variables affect cooling system cost.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Turbines	Pollution Control	13B	
Cooling Systems	Heat Transfer	Stationary Sources	13A	20M
Cooling Towers	Fluid Flow		07A, 13I	20D
Design Criteria			14A	
Engineering Costs				
Condensers				

18. DISTRIBUTION STATEMENT Unlimited
19. SECURITY CLASS (*This Report*) Unclassified
20. SECURITY CLASS (*This page*) Unclassified
21. NO. OF PAGES 315
22. PRICE MF A01 PC:A14

EPA Form 2220-1 (9-73)

United States
Environmental Protection
Agency

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

EPA-600/7-78-152
July 1978

PB 285 924

EPA

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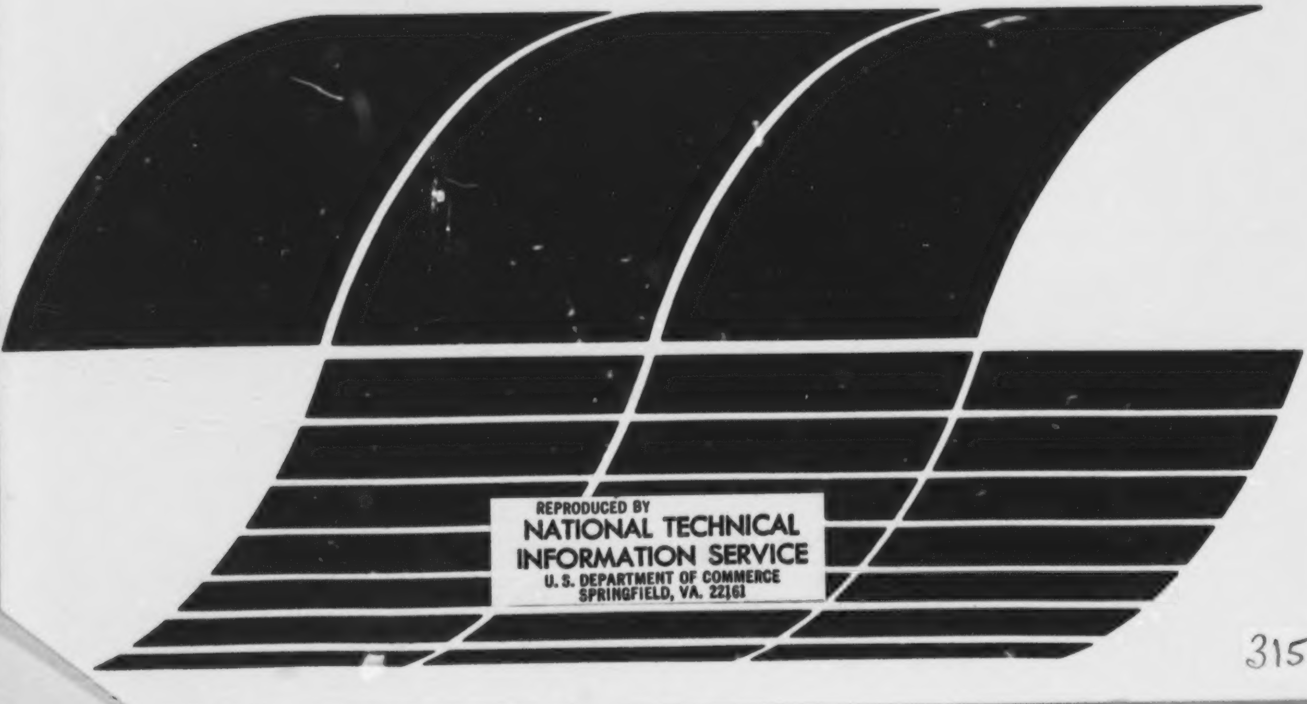
Interagency Energy/Environment R&D Program Report



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EPA-600/7-78-152
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Optimization of Design Specifications for Large Dry Cooling Systems

by

Tzvi Rozenman, James M. Fake, and Joseph M. Pundyk

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Contract No. 68-03-2215
Program Element No. EHE624A

EPA Project Officer: Theodore G. Brna

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Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

ABSTRACT

This report describes the methodology and the results of a study to optimize the design specifications of dry cooling systems for fossil power plants of the 1000 MWe size. The entire cooling system from the turbine flange outward, i.e., condenser, dry tower modules and recirculating system, is designed employing a random combination of design variables. The optimization consists of a search for the combination of design variables which will result in the lowest incremental cost of generating electricity in the plant. For each combination of variables, the total annual capital and operating costs are determined. The capital cost is evaluated in detail taking into account all stages from procurement to complete erection and installation. The operating cost includes the equivalent capital and energy cost for auxiliaries, penalties associated with loss of capacity at high air ambient temperatures, and various aspects of cooling system operating and maintenance costs. The cost base used is January 1976.

The search for the optimum combination of variables employs a multicomponent, non-linear, constrained optimization technique. Rigorous heat transfer equations were used to evaluate the performance of the condenser and the dry cooling modules at different site ambient temperatures.

All the thermal and mechanical design variables of the components of the cooling system were analyzed. These include design ambient air temperature, condenser TTD (terminal temperature difference), cooling range, and ITD (initial temperature difference). An important part of the study consists of analyzing the effect of the dry tower module design specification on the annual cost of the cooling system. The tower module design was not fixed but varied in the optimization procedure. The module variables were tube length, number of rows, pass arrangement and fan motor power. The tube employed for the tower was the overlapped, wound finned-tube of 1 in. in base diameter having 10 fins/in.

The analysis was carried out for conceptual power plants located in 5 different sites in the continental U.S. Two turbine types, combined with either surface condenser or jet condenser, were studied. Economic factors such as fuel costs, capacity factors, and energy and capacity charges were used as parameters in the evaluation.

The results of the study are presented in this report in both graphical and tabular form. The results indicate that the cost of dry cooling systems is affected by all the design variables and that simplified assumptions may lead to erroneous conclusions.

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ACKNOWLEDGMENT

PFR Engineering Systems, Inc., wishes to acknowledge the contributions and assistance of Mr. James P. Chasse, formerly of the USEPA Thermal Pollution Branch, Corvallis, OR, and Dr. Theodore G. Brna of USEPA's Industrial Environmental Research Laboratory at Research Triangle Park, NC, to the development and completion of this report.

SECTION 1

INTRODUCTION

The restrictions on the use of water resources for power plant cooling in the United States have generated wide interest in dry cooling towers. This has served as an impetus, both in government agencies and private industry, for the development of performance and economic data on these systems. The unique features and the economic characteristics of dry towers have been well documented in the literature (1-5).

The major operating characteristic of dry cooling systems is their sensitivity to the fluctuation of the ambient temperatures. This sensitivity creates special problems of loss in generating capacity at high ambient temperatures and freezing hazards at low temperatures. The outstanding economic feature is their high capital cost - an order of magnitude higher than evaporative towers. In addition, dry towers possess unique maintenance and logistic problems which arise from their overall size and multiplicity of units; i.e., modules, fans, piping, structural elements, etc.

Dry towers also introduced a new degree of complexity into the methodology of cooling system optimization. The high price of both the capital investment and the penalties due to loss of generating capacity requires careful consideration of all the interactions among the design variables. The a priori selection of some variables, such as design air temperature or fan size, might restrict the optimal solution and lead to a costlier design. An optimal design is defined as the right combination of system operating and design variables which will result in the lowest cost of producing electricity. This combination may include subsystems, such as finned tube modules or piping, that may not be optimal according to some limited thermodynamic criteria but one which will evolve in the design producing the final lowest unit energy cost. This can be recognized from the fact that dry towers include large numbers of modules requiring a large space. Considerations of structure, piping, distribution system, maintenance, manufacturing and erection techniques will produce cost factors which can be evaluated only in the context of the overall capital and operating costs.

The "heart" of the dry tower system is the set of modules of finned tubes supported by a suitable structure with large diameter axial fans inducing air flow across the tubes. Finned tubes come in different shapes, forms and sizes, differing also in their metallurgy and manufacturing methods (6). These differences produce unique heat transfer and flow resistance characteristics. Modules are constructed by assembly of the tubes into a supporting structure with proper manifolding and headers for the inlet and outlet piping connection. The manufacturing and assembly techniques and the thermal and flow characteristics of the module have a dominant role in the total cost of the cooling system, and are therefore appropriately mentioned in the introductory comments. Most existing commercial dry towers have finned tubes which are also extensively used for air coolers in the petrochemical industry. Much knowledge of dry tower technology is founded in the petrochemical industry's air cooler experience.

The strong interaction that exists among plant components in the operation and performance of the power plant dry tower requires immediate understanding. The work performed by the turbine is dependent upon the efficiency of the cooling system, which in turn depends upon the difference in temperature between the saturated steam at the turbine exhaust and the ambient air. A rise in dry bulb temperature results in a corresponding rise in turbine back-pressure and lower turbine output. This decrease is also accompanied by an increase in the amount of heat that must be absorbed in the tower. Thus, a change in ambient dry bulb air temperature changes the plant operation to a new point where the total heat rejected from the turbine again equals that absorbed by the ambient air flowing in the tower.

These variations in plant operating conditions are dependent on turbine operating conditions and the thermal performance of the cooling system. For a 1000 MWe modified conventional steam turbine operating at 14.5 in. Hg absolute back pressure (see Appendix F for conversions to SI units. British units are used throughout this report since most dry cooling tower literature employs British units), a 1.5°F increase in steam temperature at the condenser corresponds to a 3.4 MWe decrease in turbine output. Thus the performance of the cooling system components must be accurately evaluated in order to correctly represent the performance of the turbine.

An objective of this project is to evaluate the system components on the basis of heat transfer and fluid flow relationships that accurately represent plant performance instead of using approximate overall empirical formulas. The performance of the cooling system (surface condenser, piping, and dry tower modules) is a function of the design variables. These variables include pumping and fan power, water flow rate and tube velocity, tube diameter and length, number of tube rows and tube pass arrangement. The major objective of this work is to study the effect of the above design variables on the performance and the cost of dry towers.

The cost of the dry tower is very much a function of its design. The capital cost is a function of specific module design, number of modules, and construction, assembly and piping cost. The operating costs are strongly dependent on fan and pumping power and the operation of the turbine which is in turn dependent on the design variables. The study of the effect of design variables on total cost of employing dry towers cannot be accomplished without accurate and detailed analysis of all the components of the system. It was thus also within the scope of this project to develop cost analyses of dry towers which would include a detailed cost breakdown of all stages of procuring and constructing the dry tower. This approach differs from previous works in which standard designs with standard generalized cost functions were employed.

The search for the lowest cost dry tower within the wide range of design variables and cost factors requires an advanced "search" scheme. An optimization procedure was developed which searches for an optimum bounded by nonlinear constraints. This multivariable scheme selects the combination of design variables which leads to the lowest cost of owning and operating a dry tower in a power plant. The effect of the design and cost variables on overall cost are studied through a sensitivity analysis.

The objectives and scope of this work are summarized as follows:

1. Application of a general methodology for multivariable optimization
2. Application of accurate rating methods for cooling system components
3. Application of accurate and detailed cost analyses for the cooling system
4. Study of the effect of dry tower design variables on the total evaluated cost of dry towers

SECTION 2

SUMMARY

This report presents the results of an extensive computer analysis of the design and cost variables of a dry cooling system for 1000 MWe fossil fuel power plants. A computer program was developed which designs and cost estimates the dry tower components and searches for the optimal system (defined as: system with lowest total annual cost).

The dry tower system evaluated is of the indirect type in which cooling water is circulated between the condenser and air-cooled modules. Both surface condensers and direct jet condensers are being considered in this study as well as the selection of either the "high back pressure" turbine or the "modified conventional" turbine. The design methodology of the dry cooled system components does not restrict the components to preset fixed designs, but rather varies the mechanical configuration in a search for an optimal design. Condenser variables such as tube length and diameter, tube velocity and number of shells are evaluated together with circulating system flow conditions, piping design, dry tower modules, tube length, number of rows and passes, and fan power. Such design considerations require a multidimensional non-linear search technique which is incorporated in the program. For any intermediate design, the performance of the dry cooling system is evaluated for the ambient temperature fluctuation and load variation at the site. This is carried out with the aid of rigorous methods based on the principles of fluid flow and heat transfer that predict the performance more accurately than any approximate or simplified methods. Such rigorous methods are required to predict accurately the variation of plant output with the fluctuation in ambient temperatures.

The economic cost analysis is based on a constant demand of electricity according to the load duration specified, and on the average plant capacity factor. When the demand cannot be met due to deteriorated performance at high ambient temperatures, it is assumed that the supplemental power will come from either peaking gas turbines or built-in expended plant capacity. In both alternatives the extra capacity and energy penalties are added to the capital cost of the cooling system. Other penalty costs include the cost of the incremental steam supply system and fuel cost for the turbines as compared with a "standard" low pressure turbine that provides design capacity at 2.5 in. Hg absolute.

The dry tower designs were evaluated for 5 sites and assumed January 1976 construction start-up. Basic economic factors were parametrically varied and the results are illustrated in tabular and graphical forms.

SECTION 3

CONCLUSIONS

1. The annual cost of a dry cooling system for power plants is dependent on all the operational and design variables of the cooling system. A search for an optimal design would be best carried out by investigating the combination of all variables which will lead to lowest annual cost. The methodology utilized in this work removes many of the uncertainties associated with simplified approximate methods.

2. The computer analysis has shown that there exist several combinations of system variables which will result in lowest annual cost of cooling systems. The availability of several unique optimal systems can provide leeway for configuration of design preferences. However, deviation of one or more variables from the values of the optimal combinations may result in higher cost.

3. Ambient site temperature fluctuations are of great significance to tower design, and therefore cost. Both the maximum temperature of the site and the annual temperature duration curve contribute to the effect on design and cost.

4. Fuel cost has an important effect on the total annual cost and the design variables. The difference in dry tower cost for a "high back pressure" turbine and a "modified conventional" turbine used at the same site is primarily a function of fuel cost. As the fuel cost increased the dry tower combined with the "modified conventional" turbine became cheaper than a dry tower combined with a "high back pressure" turbine. This is because the incremental fuel cost of the high back pressure turbine erodes the advantage of the tower's lower capital cost and energy penalties. For relatively low fuel cost and sites with relatively hot climates, the "high back pressure" turbine design is cheaper.

5. The use of jet condensers results in reduced annual cost of about $200,000 as compared with a system utilizing surface condensers for a unit fuel cost of $0.75/MMBTU. The jet condenser requires higher pumping power, and for higher fuel cost the difference between the cost of systems with surface condensers becomes negligible as compared with the direct jet condenser system.

SECTION 4

INTERACTION AND RATING OF PLANT COMPONENTS

The indirect dry cooling system, which is being studied, consists of the low pressure turbine, a surface or direct contact condenser, cooling water piping system, and the dry tower. Figure 4.1 shows the system in a schematic diagram. A description of each element follows in the succeeding sections.

4.1 System Thermal Interaction

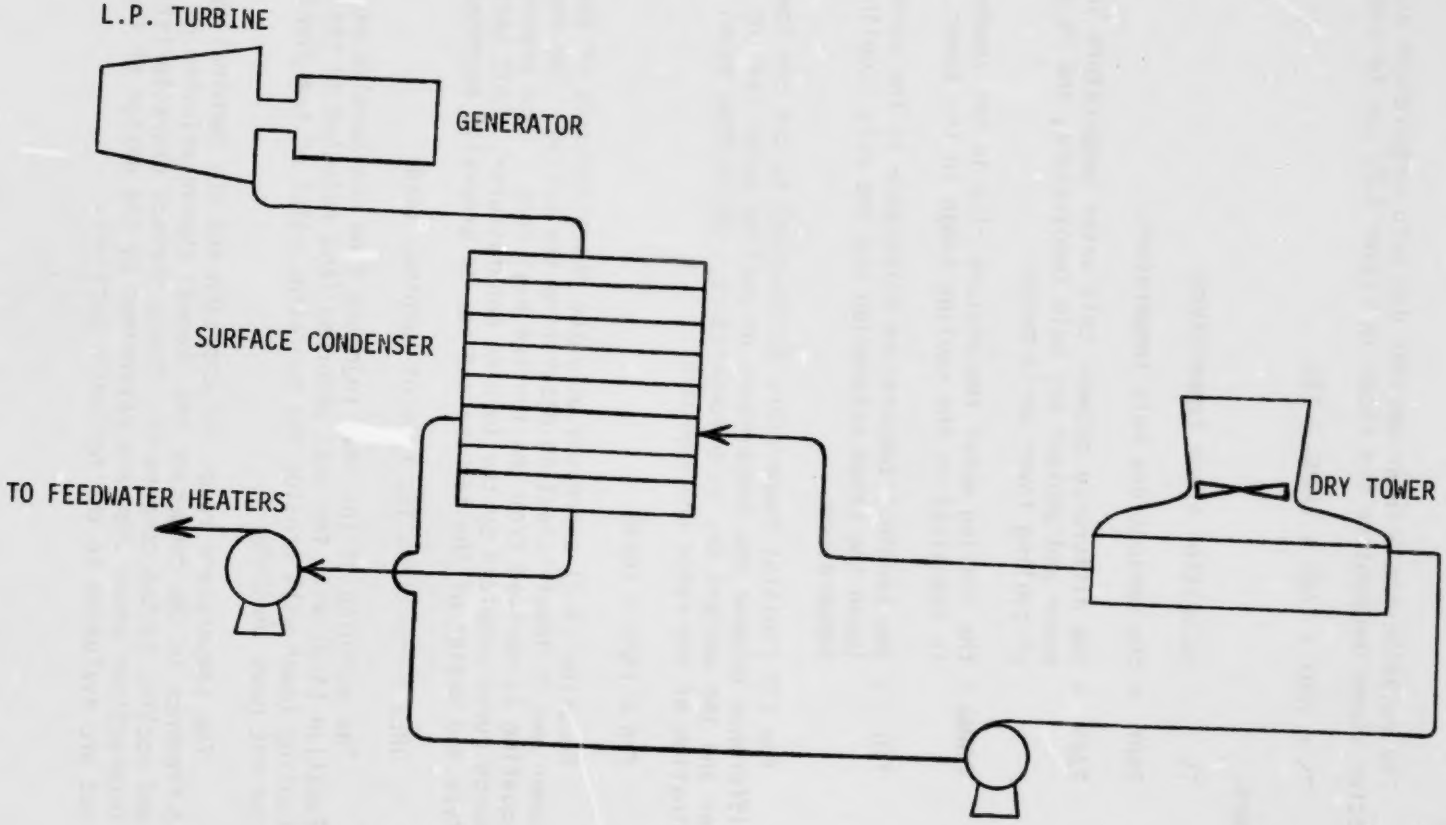
The selection and design of a heat rejection system for a power plant is a complex process involving many variables. Economic, environmental, and engineering considerations among others constitute both the guidelines and constraints. Even though the final decision on a system does not evolve from pure analytical considerations, the more quantified the interactions among the variables, the less ambiguous and uncertain will be the final decision. This is the basic approach that PFR is advancing in this project.

Figure 4.1 shows a schematic diagram of a portion of a plant equipped with a dry cooling tower. Steam from the turbine flows to a condenser, and the condensate is pumped to feedwater heaters for reheat. The cooling water absorbs the latent heat from the steam and then is cooled in the cooling tower. This is the basic cooling water recirculating system that is considered in this project.

In the closed cooling system utilizing dry towers, the heat from the condensed steam is rejected to atmospheric air. The plant output is affected by the interaction of all the system components in this heat rejection process. The term "interaction" refers here to the effects that the changes in operating conditions in one component of the system have on the performance of the other components. This interaction will essentially determine the power output at each ambient temperature.

The power output is a function of the condenser pressure or steam saturation temperature. The condenser pressure is determined by the ability of the condenser to transfer the latent heat of steam to the cooling water. This is a typical heat transfer process depending on water flow rate and inlet temperature and size of the condenser.

The water inlet temperature is in turn a function of the tower performance which is determined by tower design and ambient dry bulb temperature.



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TO FEEDWATER HEATERS
DRY TOWER

Figure 4.1. Schematic Diagram of a Dry Cooling System.

The relationship between ambient dry bulb temperature and the saturation steam temperature (as shown in Figure 4.2) can be expressed as:

$$\mathrm{TS} = \mathrm{TDRY} + \mathrm{TAPP} + \mathrm{TRANG} + \mathrm{TTD} \qquad (4\text{-}1)$$

where,

TS = saturation steam temperature.

TDRY = the ambient dry bulb temperature.

TAPP = the difference between cold water temperature leaving the tower and ambient dry bulb temperature, and is a function of cooling tower performance.

TRANG = the cooling water temperature rise in the condenser which is identical to the cooling range in the tower.

TTD = the terminal temperature difference in the condenser between the steam saturation and the exit (cooling water) temperature.

The ITD (initial temperature difference) in the dry tower is the difference between the temperature of cooling water leaving the condenser and the ambient dry bulb temperature. It is thus equal to the combination of the range and approach:

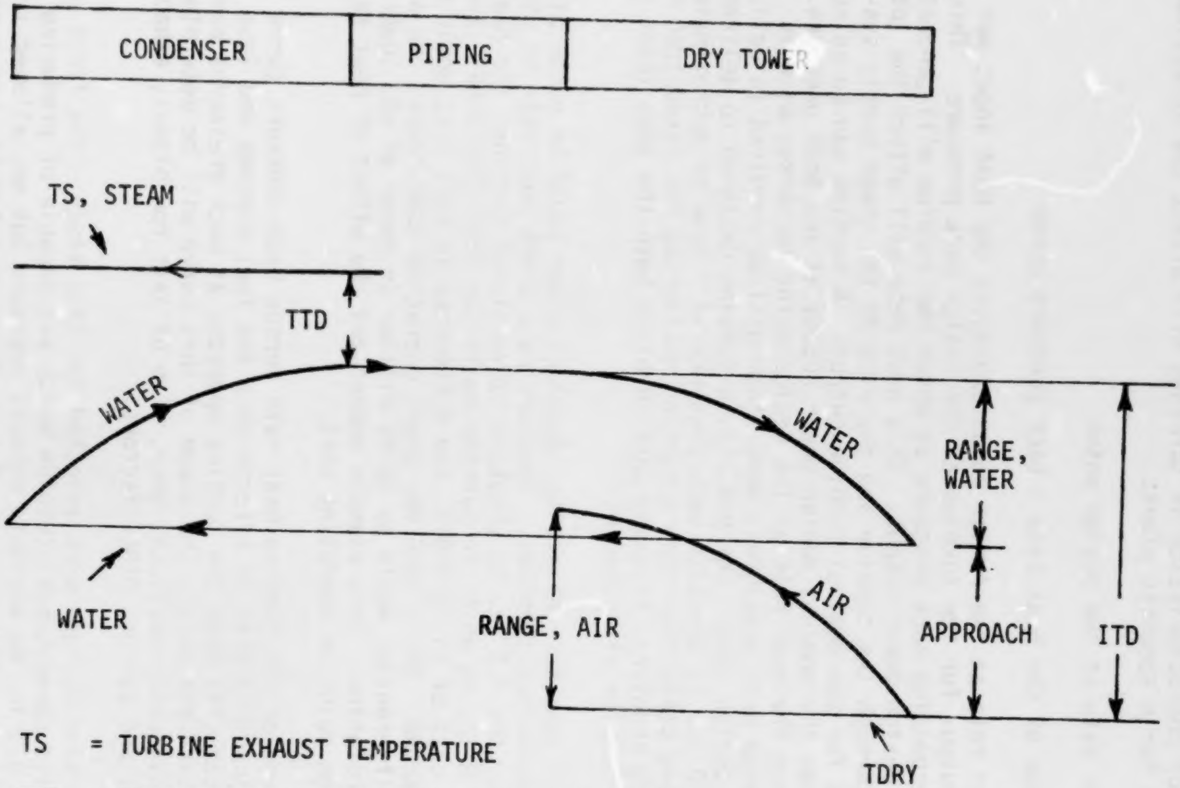
$$\mathrm{ITD} = \mathrm{TAPP} + \mathrm{TRANG} \qquad (4\text{-}2)$$

Equation (4-2) expresses only the characteristic of the cooling tower and is insufficient in describing the system. The complementing equation is derived from the turbine heat rate - back pressure performance curve provided by the turbine manufacturer. This varies with the type and design of the turbine and can be generally expressed as:

$$\mathrm{QREJ} = \text{function (TS, type of turbine, load)} \qquad (4\text{-}3)$$

The matching of the heat rejected from the turbine expressed by Equation (4-3) with the heat absorbed (and rejected to the air) in the cooling tower will provide the operating point of the plant and thus the net power output.

The temperature range and approach and the terminal temperature difference in the condenser are thermal characteristics of the turbine and cooling system components. These thermal characteristics and the interactions among them are determined by the design of the components and are evaluated in the following sections.


CONDENSER
PIPING
DRY TOWER
TS, STEAM
TTD
WATER
WATER
RANGE, WATER
WATER
RANGE, AIR
AIR
APPROACH
ITD
TDRY

TS = TURBINE EXHAUST TEMPERATURE

TTD = TERMINAL TEMPERATURE DIFFERENCE FOR CONDENSER

ITD = INITIAL TEMPERATURE DIFFERENCE FOR DRY TOWER

TDRY = AMBIENT DRY BULB DESIGN TEMPERATURE

Figure 4.2. The Relationship Between Temperatures in the Cooling System Components.

4.2 Turbine Selection

Two major characteristics of turbines will affect the selection of a turbine for a specific plant:

1. Heat rate at the design point
2. Shape of the heat rate - back pressure curve

The heat rate at the design point expresses the heat input per unit power output for the turbine at the design back pressure. This is the corresponding back pressure at which the turbine will generate the nominal design power output. This heat rate will affect the total steam flow through the turbine and the size of the steam supply system required for the nominal turbine output. A turbine can be selected to provide the nominal design power output at any back pressure. However, since the heat rate at the design point increases with increasing design back pressures, more steam will be required to deliver the nominal design load. For example, a turbine designed to deliver 1000 MWe at 8 in. Hg absolute back pressure will require approximately 7 percent more steam flow than a turbine delivering its rated 1000 MWe at 3.5 in. Hg absolute, assuming both turbines have the same inlet conditions and turbine efficiencies.

The fuel cost for delivering identical power would be quite different for these two turbines. Considering a gross heat rate of 8941 BTU/KW-HR for the 3.5 in. Hg absolute conventional turbine, the heat rate for an 8 in. Hg absolute turbine would be 9576 BTU/KW-HR. Assuming a fuel cost of $1.00/MMBTU, the difference in fuel cost would be .635 mills/KW-HR. For a 1000 MWe plant operating 6000 hours, the annual cost differential would be $3.81 million in favor of the lower heat rate operation. This example emphasizes the effect of heat rate at the design point on operating cost.

The shape of the turbine heat rate versus back pressure curve is also significant in that it affects both the fuel economy and loss in generating capacity when the turbine operates at back pressures above the design back pressure. The shape of this curve will be determined by the exhaust cross-sectional area, size of last row blades, exhaust Mach number, and various other factors.

Two turbine designs were selected for this study. The first one was a modified conventional turbine which was capable of producing 1000 MWe at 3.5 in. Hg absolute exhaust pressure but was allowed to exhaust as high as 15 in. Hg absolute. The second turbine was a high back pressure turbine which was capable of producing 1000 MWe at 8 in. Hg absolute and was also allowed to operate up to 15 in. Hg absolute. Both full load and partial load data for these turbines are available from the General Electric Company (7). Appendix A shows the heat rate performance of the conventional, modified conventional, and high back pressure turbines. Also, this appendix shows the heat rejected as a function of the back pressure for the modified conventional and high back pressure turbines. These performance graphs, combined with steam properties, can be curve-fitted to analytical expressions or tabular values as a function of condensing temperature, TS. For each load percentage, two analytical expressions can be derived from curve fitting:

$$\text{QREJ} = \text{function (TS, type turbine, load)} \tag{4-3}$$

$$\text{PGEN} = \text{function (TS, type turbine, load)} \tag{4-4}$$

Equation (4-3) expresses the total heat rejected, QREJ, as a function of steam temperature, and Equation (4-4) expresses the corresponding net power generated, PGEN, at that exhaust steam temperature, TS. As TS increases, QREJ also increases but PGEN decreases. It should always be borne in mind that QREJ, PGEN, and TS are not fixed but vary with ambient temperature.

4.3 Condenser Selection

The condenser component of the cooling system determines the terminal temperature difference, TTD, between the hot water leaving the condenser and the steam saturation temperature. Both the direct contact, jet-type condensers and surface condensers were studied in this work.

4.3.1 Jet Condenser

The jet condenser was developed specifically for dry tower application, and there exist several reports that outline its design and performance characteristics (8, 9). In the jet condenser, water is sprayed through multiple nozzles into a core of flowing steam. Under ideal mixing conditions no temperature difference exists between the hot water and the saturated steam. Early reports on jet condensers quoted a 0.5^{o}F terminal temperature difference. However, in a recent report of an installation in the Soviet Union (10), a temperature difference of 2^{o}F was noted. This temperature difference varied somewhat with the heat load. In the present study, the TTD in the jet condenser at full design heat load was set to 2^{o}F. At other loads, the TTD was set proportional to the heat rejected according to:

$$(\text{TTD}) = (2.0)\ \frac{\text{QREJ}}{\text{QREJD}} \tag{4-5}$$

where,

QREJD = the design rejected heat load.

QREJ = the variable heat load.

TTD = the terminal temperature difference in the jet condenser at the corresponding heat load, QREJ.

The jet condenser design will also affect the circulating water pumping power through the spray nozzle pressure drop. This is explained in more detail in Section 4.6 in the discussion on piping. The pressure drop through the nozzles was assumed fixed at 13 ft. of water.

4.3.2 Surface Condenser

The design and the performance of surface condensers are a function of both the flow conditions and the mechanical construction. Tube side velocity, tube diameter and length, number of passes, etc., are all important variables. Since the reduction in back pressure is of prime importance in dry cooling systems, multiple pressure condensers are employed. The basic design equations for a single pressure condenser, or for each individual pressure compartment in a multiple pressure condenser, can be written as follows:

$$\text{QREJ} = (M\,C_p)_{\text{water}}\,(\text{TRANG}) \tag{4-6}$$

$$\text{QREJ} = (\text{U})\,(\text{AC})\,(\text{TRANG})/\ln\left(1 + \frac{\text{TRANG}}{\text{TTD}}\right) \tag{4-7}$$

where,

QREJ = the total heat rejected in a single pressure condenser or the heat rejected per compartment in a multipressure condenser.

$(M\,C_p)_{\text{water}}$ = the product of water flow rate and specific heat.

TRANG = the overall condenser range or the compartment range for a multipressure condenser.

U = the overall heat transfer coefficient based on area AC.

TTD = either the overall terminal temperature difference or the temperature difference between the saturated steam and the exit water temperature from each multipressure condenser compartment.

AC = the condenser surface area or the compartment surface area.

In a multipressure condenser, the overall heat rejected is equal to the sum of the heat rejected in each compartment. The overall TTD is the difference between the saturation temperature (corresponding to the average of the compartment pressures) and the last compartment water exit temperature. Equations (4-6) and (4-7) show that for any given combination of specified TTD, TRANG, and waterflow rate there exist multiple designs which will provide the same product (U) (AC).

These designs can employ different tube diameter and length and also different flow velocities. Normally, the flow velocity is around 7 ft/sec and it rarely deviates from a range of 6 - 8 ft/sec. An optimal selection of design variables for the surface condenser is the one which has the smallest effect on the cooling system total evaluated cost. This cost is affected by the capital cost of the condenser and by the operating cost of pumping the water through the condenser. The operating cost consists of both the extra capacity and energy charges for the pumping power. The prediction of the performance of the condenser involves a procedure which is somewhat different from the design, since for a given condenser both its range and TTD will vary as a function of the heat load. A flow diagram for the condenser design procedure is given in Figure 4.3.

4.4 Mechanical Draft Dry Tower

In a mechanical draft tower the finned tubes are assembled into bundles with common inlet and exit headers. The bundles are in widths commensurate with the shipping requirement, no wider than 14.5 ft. The shipped bundles are assembled in the field into bays or modules which are served by one or more fans through common plenum chambers. A sufficient number of modules to satisfy the heat transfer requirement of the plant is arranged in the dry tower. Water is circulated through the modules via a main piping system and distribution manifolds. Illustrations of the general layout of dry towers are given in vendors' publications (11, 12) and are not depicted here. The finned tube used in this study is the helically-wound, L-shaped, footed fin. The tube base diameter is 1 in. with the fin diameter being 2¼ in. and fins spaced 10 fins/in. These tubes are arranged in an equilateral triangular pitch with ¼-in. clearance between fins. The tubes are inclined to facilitate drainage.

The cooling system of a power plant incorporating modules of various design was optimized, and the effects of these designs on total evaluated cost were studied. The following design specifications were used as variables:

1. Tube length
2. Number of rows
3. Number of passes
4. Fan power

4.4.1 Tube Length

The module tube length affects several aspects of the dry tower. The longer the tubes, the fewer the number of modules required for a specified heat load. This will result in towers with a shorter longi-

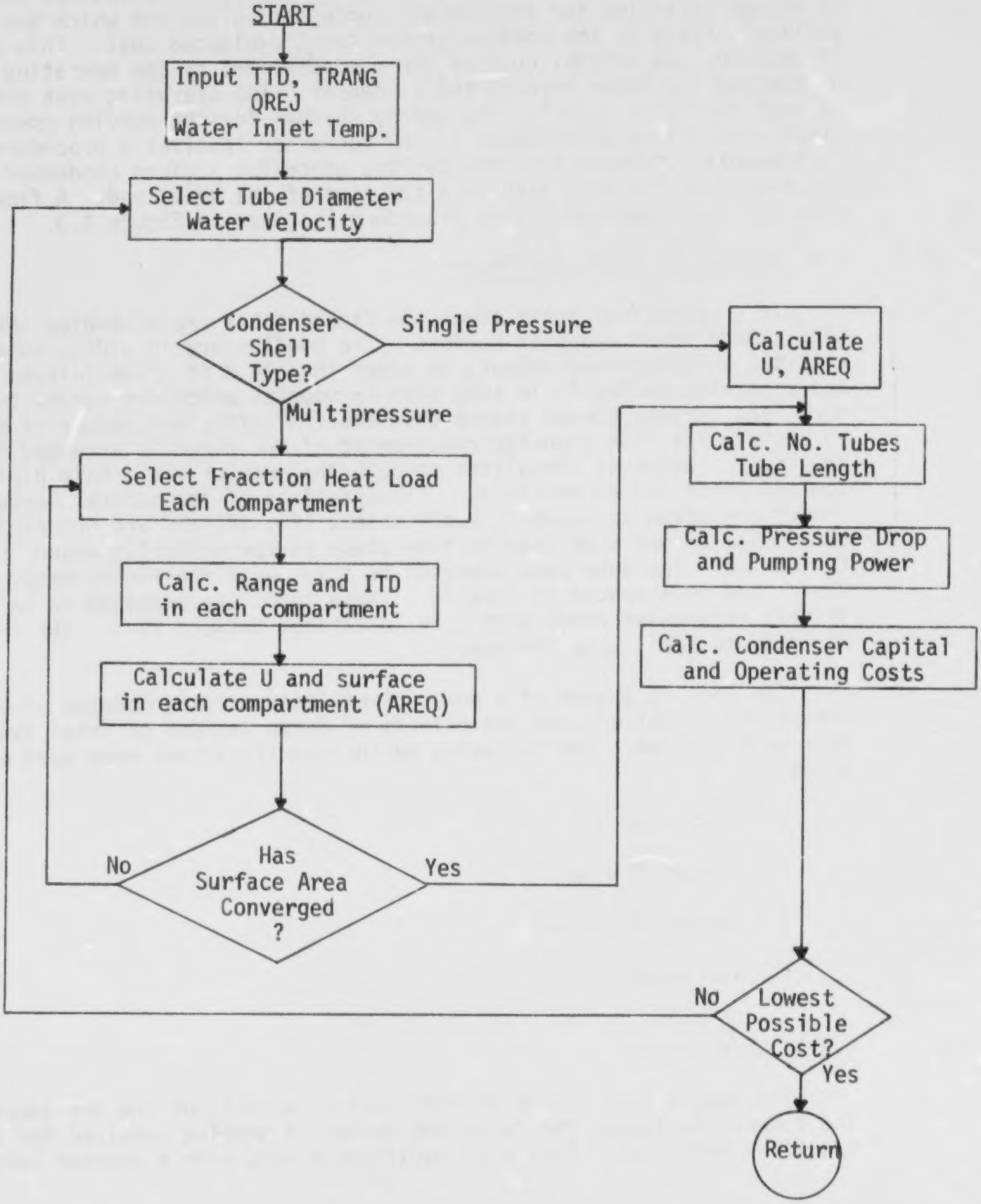

START
Input TTD, TRANG
QREJ
Water Inlet Temp.
Select Tube Diameter
Water Velocity
Condenser
Shell
Type?
Single Pressure
Multipressure
Calculate
U, AREQ
Calc. No. Tubes
Tube Length
Calc. Pressure Drop
and Pumping Power
Calc. Condenser Capital
and Operating Costs
Select Fraction Heat Load
Each Compartment
Calc. Range and ITD
in each compartment
Calculate U and surface
in each compartment (AREQ)
No
Has
Surface Area
Converged
?
Yes
No
Lowest
Possible
Cost?
Yes
Return

Figure 4.3. Surface Condenser Design Procedure.

tudinal length and with cheaper piping. The cost of unit surface area per module is cheaper when longer tubes are used. The disadvantage of longer tubes lies in increased shipping and handling expenses. Longer tubes also require increased structure height to provide adequate flow conditions for the induced air. In some cases modules with different tube lengths will accomodate fan sizes that result in increased efficiency. The tube length variation in this study ranged between 40 and 80 ft.

4.4.2 Number of Rows

The number of rows in a module is a major design variable which affects both the capital and operating cost of the dry tower. The number of rows pertains to the number of tubes per unit module width in the direction of air flow. Figure 4.4 shows a schematic diagram of a module constructed with 4 rows. Modules with more rows have higher surface area and less piping and ground area. Also, the cost of module unit surface area decreases with the increase in number of rows. However, the resistance to air flow and, hence, the required fan power increases as the number of rows increases. Also, the increase in number of rows results in heavier modules requiring stronger supporting structure. Thus, the number of rows has several offsetting effects on both the cost of the module and the fan power. In this work, the dry tower analysis was made with modules having either 4, 5 or 6 rows.

4.4.3 Number of Tube Passes

The number of passes pertains to the configuration of water flow path through the module. In a single-pass module, the water is distributed in the inlet header to all the tubes in the module and exits through another header situated at the other end of the tubes. In a 2-pass module, water is distributed from the inlet heater to half of the tubes, flows to the other end of the tube, and turns to flow in the other half before exiting at the same end as the inlet. Figure 4.5 illustrates schematically a module with 2 passes.

The number of passes has several effects on the mechanical design and the performance of dry towers. The pass configuration is achieved by constructing the header with proper partition plates which divide the header into pass compartments. These partition plates are welded in the header and increase the cost of the module. The piping system design and layout is affected by the pass number. With an even number of passes, the water enters and exits the module on the same side. The main feed and return pipes as well as the distribution manifolds are all located on one side of the module, requiring greater care for proper layout and construction design. With an odd number of passes the feed and return piping are located on opposite ends of the module length.

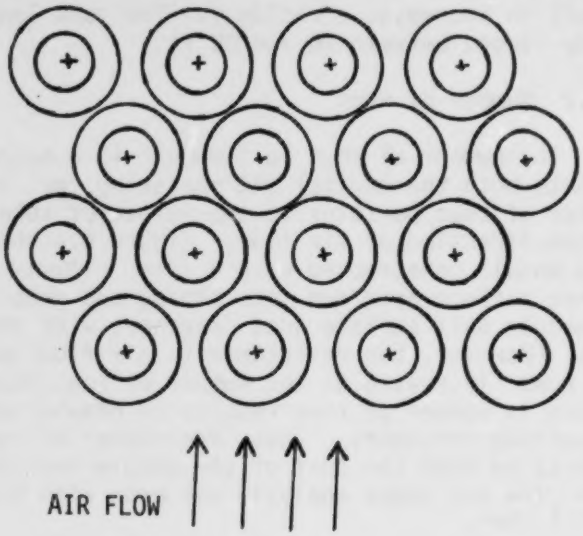


Figure 4.4. Four-Row, Round Fin Staggered Module Arrangement.

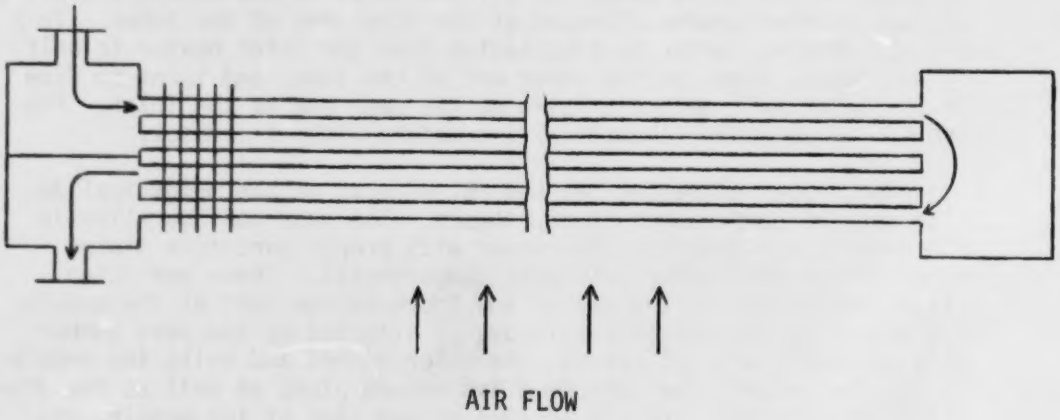


Figure 4.5. Four-Row, Two-Pass Heat Exchanger Arrangement.

The number of passes also affects the thermal and hydraulic performance of the module. When the number of rows and tubes and the flow rate remain unchanged, increasing the number of passes will proportionally increase the tube flow velocity. This will result in an increase in the tube-side heat transfer coefficient but also will increase the pumping power because of the increase in the tube-side pressure drop. Furthermore, increasing the number of passes increases the mean temperature difference (MTD) of the module and hence increases the effectiveness of the module.

4.4.4 Fan Power

The characteristics of the fans in dry cooling modules may provide added degrees of freedom in their design and operation. The heat rejection capability of a module with a fixed configuration increases with the increase in fan power. A dry tower may have few modules with "powerful" fans inducing high velocity, high volume air flow, or it may have many of the same size modules with less powerful fans. In either case, the total design heat load of the tower remains unchanged. For a specified design heat rejection and ITD, the total fan power requirement decreases with an increase in the number of modules of a given surface area. Thus, there exist numerous alternatives for a dry tower design based on the number of modules and the associated fan power.

The fans employed in dry towers are large diameter axial fans. A characteristic of these fans is that they induce a large air flow rate under a low pressure drop, less than 1.0 in. water. The fans may have between 4 and 12 blades rotating at tip speeds of 12,000 ft/min or less. Fan performance is described by characteristic curves which present the delivered air flow rate as a function of flow resistance (pressure drop) and fan speed. The mechanical efficiency of the fan, defined as the conversion of motor power to actual power delivered to the air, is also a function of the operating conditions of the fan. The fan selection for a dry tower is a major design variable and affects both the performance and capital and operating costs of the dry tower. The selection of the optimized fan for the cooling tower was made according to the method described by Monroe (13).

4.4.5 Dry Tower Design and Rating

The design and rating of dry tower modules involve the calculation of internal tube-and air-side heat transfer coefficients and pressure drops and mean temperature difference. These variables are dependent on either the specific module design or fan power, or both, as explained in the previous sections. Data for the heat transfer process in dry cooling modules are available in published reports (6). The performance of mechanical draft towers is evaluated by the procedures established in Kays and London (14) as explained in Appendix G.

The heat rejection capability of a dry tower is expressed as:

$$QTOW = (N)_{mod}(ITD)\ (MC_p)_{mod}(P) \tag{4-8}$$

where,

N_{mod} = the number of identical modules.

$(MC_p)_{mod}$ = the product of air flow rate and specific heat of air in a module.

P = the heat exchanger effectiveness, ratio of air temperature rise to ITD for $(MC_p)_{air} < (MC_p)_{water}$.

ITD = the initial temperature difference between the hot water and ambient air.

The $(MC_p)_{air}$ is primarily dependent on fan power. The effectiveness, P, is a function of the number of heat transfer units, NTU; the capacity ratio, R; and the flow and pass arrangement. The NTU and R are defined as follows:

$$NTU = \frac{(U)\ \ (A)}{(MC_p)_{air}} \tag{4-9}$$

$$R = \frac{(MC_p)_{air}}{(MC_p)_{water}} \tag{4-10}$$

where,

U = the overall heat transfer coefficient based on area A.

A = the total finned-tube heat transfer area.

U is a function of the tube-and air-side coefficients, tube wall conductance, and the fouling resistances. The tube-side coefficient is primarily a function of the circulating water flow velocity. The relation between P, NTU, and R for crossflow is given graphically by Kays and London (14) and has been analytically formulated into PFR's computer program. Equations describe the relation between the ITD and the heat rejected. This relationship is quite complex and is dependent on the effectiveness and the air and water flow rates.

In the design and performance evaluation of the dry tower, the actual heat transfer characteristics are calculated for specified conditions. Total flow resistance across the dry module is used to calculate fan power. The pressure drop inside the tubes is used along with all other losses of the water distribution system to calculate pumping power.

4.4.6 Combined System Performance

The performance of each component of the cooling system (i.e., condenser, piping, cooling tower) is coupled to other components through the heat rate vs. back pressure characteristics of the turbine. The combined system performance is determined by the interaction of the individual components which are linked through their thermal performance. Equations (4-3) through (4-10) form the link between turbine back pressure and ambient air temperature. These can be summarized as follows:

$$\text{QREJ} = \text{function (TS, load)} = \text{turbine heat rejected} \qquad (4\text{-}3)$$

$$\text{PGEN} = \text{function (TS, load)} = \text{turbine power output} \qquad (4\text{-}4)$$

$$\text{QTOW} = (\text{N})_{\text{mod}}(\text{ITD})(\text{MC}_p)_{\text{mod}}(\text{P}) = \text{tower heat rejected} \qquad (4\text{-}8)$$

$$\text{TS} = \text{TDRY} + \text{ITD} + \text{TTD} = \text{steam saturation temperature} \qquad (4\text{-}1)$$

$$\text{ITD} = \text{TRANG} + \text{TAPP} = \text{initial temperature difference in the tower} \qquad (4\text{-}2)$$

These equations describe the thermal interaction between the various components of the cooling system. For any given ambient temperature, TDRY, the above equations will determine TS and thus the turbine power output, PGEN. The above equations also establish the number of independent variables that are sufficient to describe the system. For a dry tower module of specified design (i.e., fixed tube diameter and material, number of rows and number of passes), there are 6 variables that describe the system. They are: ITD, TTD, TRANG, TS, tube length, and fan power per module. The optimum design will be the one in which the right combination of the above variables will lead to the lowest incremental cost of producing electricity.

It is conceivable that different combinations of design variables will lead to several low incremental costs within a ± 1.0 percent differential from each other. This is a common result when optimizing a cost which is a function of multivariables. For example, a design with few modules with "powerful" fans may have the same cost (within ± 1.0 percent) of a design consisting of a large number of modules and smaller fan power. However, these designs may differ by plot area or actual length of piping. Such differences may point to a preference of one design over the other simply on the basis of construction logistics and maintenance problems which may not be reflected by the cost factor. In reviewing the various design combinations which produce the lowest incremental bus-bar cost, it is thus possible to select the best design which conforms to the particular conditions of a specific project.

4.5 Dry Tower Piping System

The piping system consists of carbon steel pipes arranged above ground to provide equal water flow to each tube module. The main supply and return lines are designed with appropriate valving to bypass the dry cooling towers and to isolate the circulating pumps and water recovery turbines. In addition, storage tanks with fill pumps, valving and fill piping are included to facilitate easy draining or filling of the dry tower. All piping includes expansion joints to relieve any thermal expansion. In general, all pipes are standard wall and designed for a water velocity between 8 and 12 ft/sec.

As much shop work as possible is done in order to reduce the amount of expensive field work that is needed. The assumptions that were used in this work are:

1. Pipes below or equal to 4 ft. in diameter are made in 40-ft. lengths with 2 lengths butt-welded together in the shop.
2. Pipes between 4 and 8 ft. in diameter are made in 12-ft. lengths with 4 lengths butt-welded together in the shop.
3. Pipes between 8 and 12 ft. in diameter are made in 12-ft. lengths with 2 lengths butt-welded together in the shop.

4.5.1 Distribution System

Cooling water is pumped from the main condenser to the dry tower which is located 500 ft. away. The supply line enters perpendicularly at the middle of the tower and branches in both directions to supply water along the entire length of the tower. At each bay (3 tube bundles with a common header) a feeder line rises to a bay distribution manifold. The feeder lines are adequately valved in order to shut off water flow to the entire bay. The bay distribution manifold then distributes the water to the inlet headers of the 3 tube bundles. In order to keep piping costs at a minimum, the size of the supply and return lines reduce in size as the water flow rate decreases along the length of the tower. The return scheme is identical to the supply scheme.

Four possibilities exist as to the general layout depending on the total water flow rate and the number of tube passes. With an even number of passes, the supply line runs down the middle of the tower, and there are 2 return lines also running down the middle on either side of the supply line. With an odd number of passes there are 2 supply lines which run along both sides of the tower. A single return line runs down the middle of the tower. In addition, a large water flow rate might necessitate supply and return lines larger than 12 ft. in diameter. In this case, 2 supply and 2 return lines are needed. This would change the piping arrangement slightly at the entrance to the tower for both the even and the odd number of tube pass situations. Figure 4.6 is a schematic drawing of the piping for an even number of passes. Figures 4.7 through 4.10 depict all 4 possibilities for the return and supply piping.

4.6 Piping Pressure Drop

The pressure drop of the piping system is calculated by determining the loss through each section of the piping, taking into account losses from valves and elbows. By changing the supply and return line pipe diameter to keep the water velocity nearly constant, there will be no momentum losses or maldistribution in the system. Figures 4.7 through 4.10 denote the various piping diameters with numbers. The total pumping head depends on the type of condenser.

4.6.1 Surface Condenser Pumping Head

For a surface condenser the pumping head is the sum of the tube bundle, supply and return piping, and condenser losses. Normally the pressure drop of the supply and return lines is the smallest component of the total pumping head. The dry tower tube-side and the condenser pressure drop are of the same order of magnitude as shown in Table 4.1.

The major constraint is to ensure that the operating pressure for the condenser does not exceed the limit of the waterbox design pressure.

4.6.2 Direct Contact Condenser Pumping Head

In a direct contact condenser the cooling water mixes with the steam turbine exhaust. It is thus of prime importance to prevent ambient air from leaking into the circulating system. The hazard of leakage exists due to the vacuum conditions in the condenser which is now part of the cooling water circulation loop. To prevent this hazard, the water circulating pump raises the pressure so that the water in the piping system is above atmospheric pressure. The pumping conditions are such that at the highest point (about ground level) in the circulating system, the pressure is 3 ft. above atmospheric. Hydraulic turbines are placed upstream of the spray nozzles to recover part of the head delivered by the pump while reducing the cooling water pressure to the conditions in the jet condenser.

The pump must overcome the head difference between the top of the condenser where the water is sprayed and the bottom of the condenser where the liquid water level is. In addition, the pump must overcome the spray nozzle drop, the tube bundle loss, and the return and supply piping losses. For a 1000 MWe plant, the total pumping head is approximately 140 ft. of water. The drop across the recovery turbine will be about 75 ft., 80 percent of which can be recovered while producing useful power.

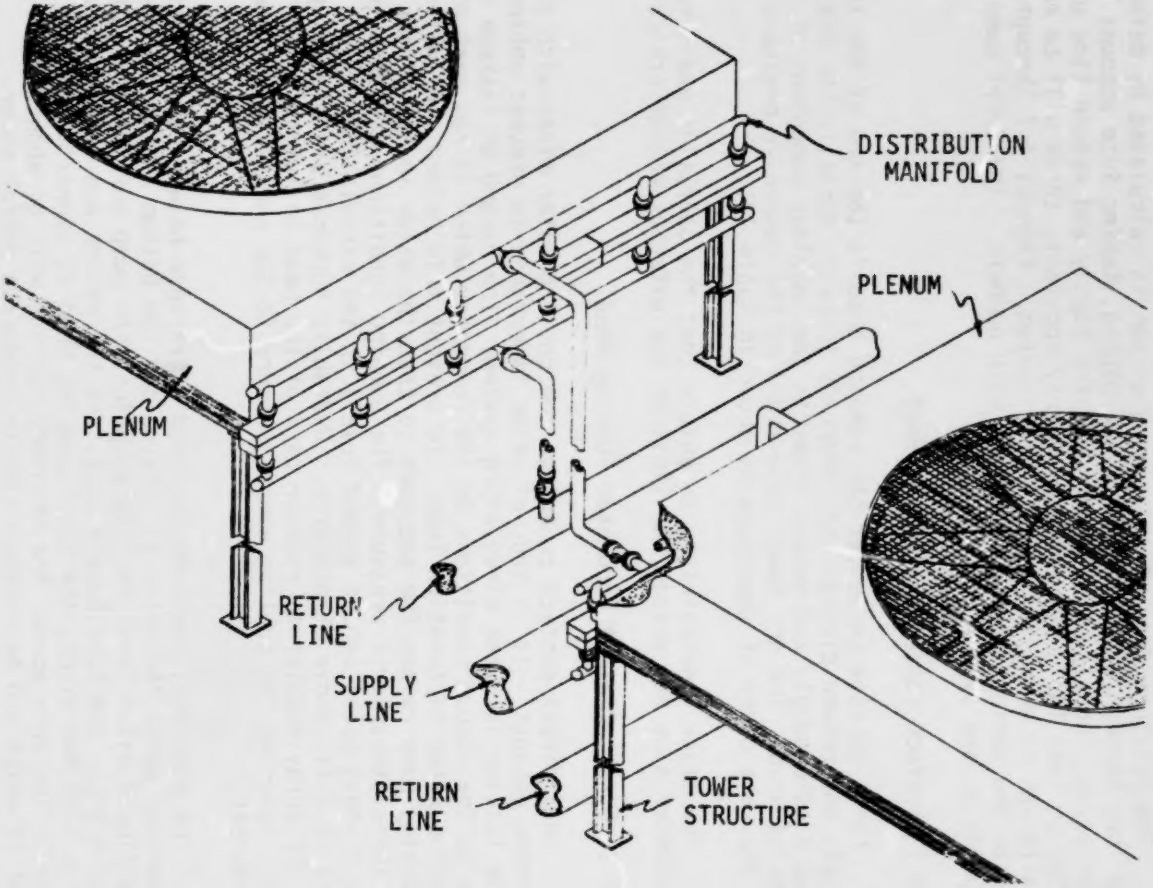
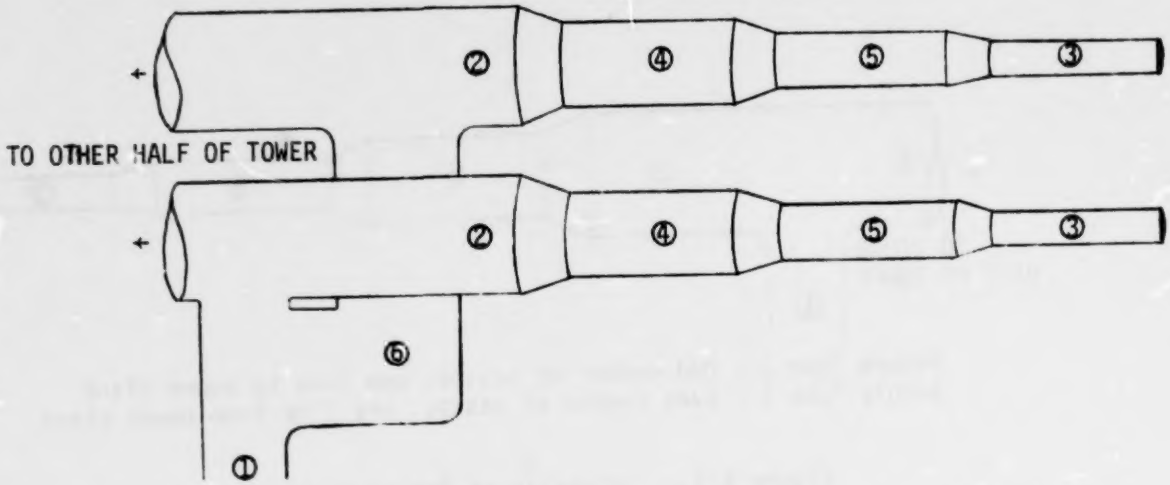
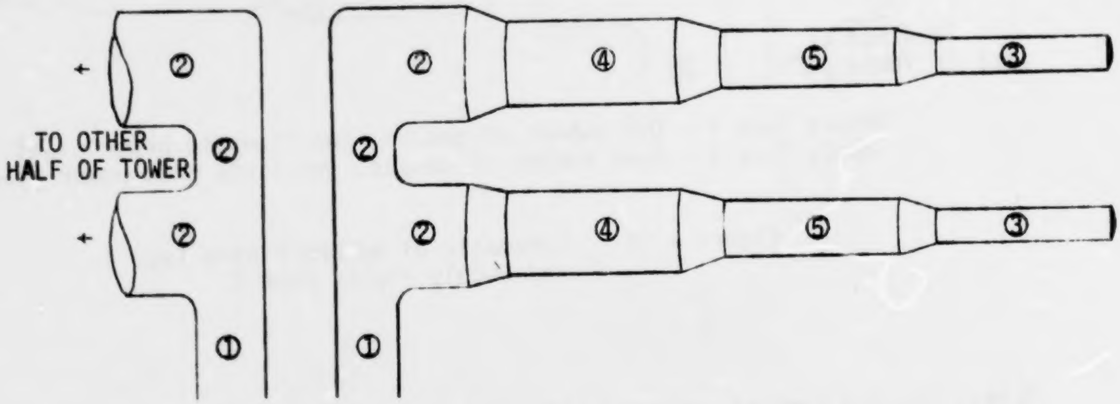

DISTRIBUTION MANIFOLD
PLENUM
PLENUM
RETURN LINE
SUPPLY LINE
RETURN LINE
TOWER STRUCTURE

Figure 4.6. Water Distribution System.


TO OTHER HALF OF TOWER
②
④
⑤
③
②
④
⑤
③
⑥
①

Return Type 1 - Even number of passes, one line to power plant
Supply Type 3 - Odd number of passes, one line from power plant

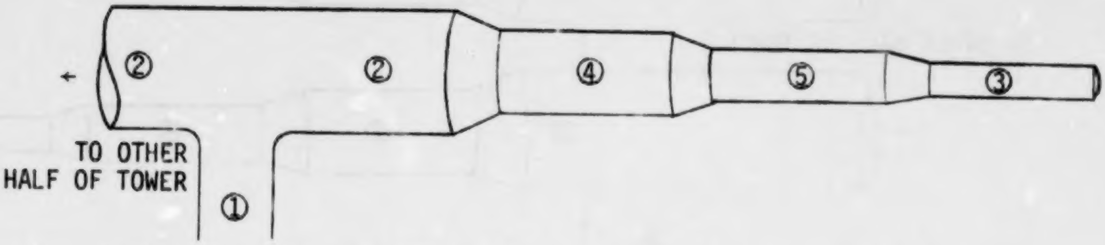
Figure 4.7. Schematic of Return Piping Type 1 and Supply Piping Type 3.


②
TO OTHER HALF OF TOWER
②
②
①
②
④
⑤
③
②
②
④
⑤
③
①

Return Type 2 - Even number of passes, two lines to power plant
Supply Type 4 - Odd number of passes, two lines from power plant

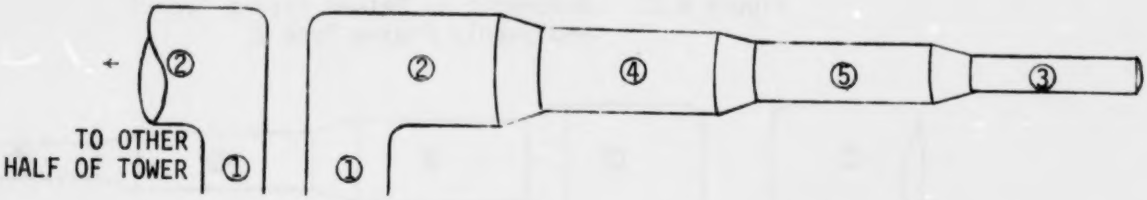
Figure 4.8. Schematic of Return Piping Type 2 and Supply Piping Type 4.

Note: Circled number refer to pipe diameter numbers used for computer output. See Table E.4.


②
②
④
⑤
③
TO OTHER
HALF OF TOWER
①

Return Type 3 - Odd number of passes, one line to power plant
Supply Type 1 - Even number of passes, one line from power plant

Figure 4.9. Schematic of Return Piping Type 3 and Supply Piping Type 1.


②
②
④
⑤
③
TO OTHER
HALF OF TOWER
①
①

Return Type 4 - Odd number of passes, two lines to power plant
Supply Type 2 - Even number of passes, two lines from power plant

Figure 4.10. Schematic of Return Piping Type 4 and Supply Piping Type 2.

Note: Circled numbers refer to pipe diameter numbers used for computer output. See Table E.4.

TABLE 4-1. REPRESENTATIVE COOLING SYSTEM HEAD LOSSES*

	Surface Condenser	Jet Condenser or Direct Contact Condenser with Recovery Turbine	Direct Contact Condenser without Recovery Turbine
Supply Lines and Distribution Piping	6.5	6.5	6.5
Tube Bundle	25.0	25.0	25.0
Return Piping	6.5	6.5	6.5
Condenser Head	---	14.0	14.0
Condenser Spray Nozzles	---	13.0	13.0
Condenser Tubes	17.0	---	---
Recovery Turbine or Throttling Valve	---	75.0	75.0
Total Pumping Head	55.0	140.0	140.0
Head Recovered by Recovery Turbine	---	60.0	---
Net Pumping Head Penalty	55.0	80.0	140.0

* in ft. of water

The main advantage of the direct jet condenser is in the lower TTD as compared to a surface condenser. However, the pumping power is higher for the direct jet condenser. For a 1000 MWe fossil plant, the direct jet condenser will require about 2.5 MWe more pumping power. Table 4.1 demonstrates representative differences in pumping heads for the different types of condensers.

4.7 Dry Cooling Tower Structure

The horizontal tube modules must be sufficiently elevated to allow proper distribution of air flow to all modules. The height of the structure varies as a function of module design and air flow rate.

The structure must be designed to support the module weight and various wind and live load conditions. The supporting structure for the dry cooling tower is a steel braced system with bracings in all 3 planes. In addition to the transverse, horizontal and longitudinal steel bracing systems, a network of I-beams and columns forms the main structure which supports the weight of the tower; the foundations for these columns consist of 3-foot-deep reinforced concrete. The structure is designed for Seismic Zone 3 with a roof live load of 40 lb/ft^2. Thus, the tower structure would satisfy building codes almost anywhere in the United States.

Proper site preparation is performed; it includes 3-foot-deep excavation, compaction, and grading. The site is cleared and prepared for an additional 30 ft. on both sides of the tower, and a paved road is constructed down one side for easy accessibility to the entire tower.

SECTION 5

ECONOMIC MODEL AND OPTIMIZATION

As discussed in the previous section, a cooling tower is a complex system whose size is dependent on many interrelated variables and whose operation affects the production of electricity in a plant. A rational application of these towers involves optimization schemes in which cost is the main factor to consider.

5.1 General Approach

Much work has been done in trying to optimize the design of large, mechanical draft cooling towers. These studies ((1), (2), (3), (4)) used approximate relations for the heat transfer process in the tower and simplified generalized cost functions. Furthermore, the optimization was performed by varying only 1, or at most, 2 variables while fixing the other variables arbitrarily. Rozenman and Pundyk (15) discuss these points in detail.

In this work the optimization of the dry tower is based on the following principles and procedures:

1. All independent variables that define and affect the design and operating conditions of the cooling tower are included in the optimization scheme. These are:
    a. Design ambient dry air temperature
    b. ITD of the tower
    c. TTD of the condenser
    d. Cooling water temperature range
    e. Overall number of modules
    f. Fan power
    g. Tube length, number of rows, and number of passes
2. Rigorous heat transfer and pressure drop calculations are made for each design at the different ambient temperatures to determine the plant performance and assess operating cost (see Appendix G).
3. The capital cost of the cooling system is evaluated for all the components of the system with detailed cost breakdown of all stages of procuring and constructing the dry tower.
4. An advanced, nonlinear, constrained multivariable optimization scheme is used to find the lowest evaluated cost of the cooling system (see Appendix B).

The cost of the cooling system is an incremental cost to the entire cost of the power plant. The cost of the turbine will not vary, however. The turbine capital cost was assumed constant during the optimization process and was not included as part of the incremental cost. The optimization objective is to design the heat rejection system which will result in the smallest incremental annual cost for producing the electricity. The annual cost is composed of the amortized capital cost (fixed rate charges) and the total operating cost.

The major capital cost components of the heat rejection system are:

1. Condenser
2. Cooling tower
3. Piping system (pumps, piping, valves, etc.)
4. Land

The major component of the direct operating cost is the fuel cost.

As discussed before, the response of the heat rejection system components to changes in ambient temperature gives rise to variation in the following factors:

1. Turbine back pressure
2. Auxiliary power requirements

An increase in turbine back pressure will cause a reduction in plant output because of the heat rate increase. Various schemes are suggested (22) to overcome the corresponding loss in capacity. These schemes may require extra capital and energy expenditures. The resulting incremental costs are significant and must be evaluated in any optimization program.

Auxiliary power is required for the pumps and fans. The auxiliary power can be provided by an incremental plant capacity increase or through the same source that makes up the loss in capacity, such as a gas turbine or an enlarged plant.

It is evident, then, that in addition to their cost, cooling towers affect the performance of the entire power cycle. Thus, the optimization is a study of the combined effect of many variables in a plant. A true optimization will result from a scheme in which the design and operating variables are freely combined to provide a cooling tower system with the lowest incremental bus-bar cost of producing electricity for a given size plant in an assigned geographical area. The interaction of variables is determined by the thermal and flow characteristics of each component in the plant as explained in Section 4.

The approach to optimization is to:

1. Identify the minimum number of variables that can be independently changed
2. Evaluate their interaction by rating methods described in Section 4
3. Determine the total annual incremental cost for each interaction
4. Employ multivariable search techniques to arrive at a combination of variables producing the lowest cost. The search technique is the Box Complex Method (16) and is explained in detail in Appendix B.

5.2 Cost Analysis

The study is made on a 1000 MWe fossil fuel plant, 2400 psig, 1000°F/1000°F, located in assigned geographical areas. Two alternate turbine designs are chosen for the plant - the high back pressure turbine and the modified conventional turbine. The heat rate and heat rejection of these turbines are shown in Appendix A. Five locations within the continental U.S. were chosen. These are:

1. Phoenix, Arizona
2. Casper, Wyoming
3. Bismarck, North Dakota
4. Atlanta, Georgia
5. Burlington, Vermont

The annual dry bulb temperature duration curves for the above sites are given in Appendix D.

The plant is a summer peaking, base load plant with an average capacity factor of 0.75. The capacity is distributed over the year as follows:

100 percent load - July, August, September

75 percent load - The rest of the year except April

Shut-down - April

The objective is to design an optimum dry cooling system which will result in the lowest incremental bus-bar cost of producing the electricity in the plant. The accounting method used here reflects actual plant operation and practice. The base plant under consideration is viewed as the best source of power. Under all conditions the steam turbine is modulated until the demand load is achieved. If the demanded load cannot be achieved, then the power must be acquired elsewhere. This outside power is assessed through capacity and energy penalties according to the price scheme selected a priori.

For a comparative analysis of all the variables considered in this study, the annual cost of each cooling system is determined by evaluating economic costs of penalties for the various components of the cooling system. These costs include the capital investment, penalties associated with loss of capacity at higher ambient conditions, and various cooling system operating costs.

5.2.1 Cooling System Capital Cost

The capital cost of the cooling system includes equipment and construction costs for the total cooling system from the turbine flange onward. This includes the cooling tower, the condenser, the circulating water system, and the indirect charges for the cooling system.

The dry tower cost was evaluated in detail, taking into account all the stages from procurement to the complete erection and installation. Because of the logistics involved with the various components of the tower and expenses incurred in field installation, the construction is based on a modular basis in which shop fabrication is maximized. The cost breakdown includes the following:

1. Cost of fabricated finned-tube bundles with proper headers, nozzles, and support plates prepared for shipping. The width of the bundle is between 12 and 14 ft. and the bundle may have 4 to 6 rows with a tube length up to 80 ft.

2. Cost of fabricated sections for the plenum and recovery stack. These sections are shipped to the construction site for installation.

3. Cost of the fans, fan motors, and gearboxes. The fans may be up to 40 ft. in diameter and have between 4 and 12 blades per fan.

4. Cost of shipping the above items

5. Cost of support structure. The cost includes the structural steel fabrication and erection, site preparation, foundation, walkways and ladders, field and shop labor, and miscellaneous painting.

6. Cost of erection of modules and fans. The shipped bundles are set and aligned on the support structure and combined together with the plenum chamber. The fans, motors, gearboxes, and recovery stacks are installed, and the fans are balanced and tested. All labor and material costs, as well as support crane costs are included.

7. Cost of pumping system. Costs of circulating water pumps and drives, water recovery turbines, pump and water recovery turbine foundation are included.

8. Cost of electrical substation and cabling. Labor and material costs, including conduit and cable for connecting the power to the fan motors and pump motors, incremental transformer and station service cost are included.

9. Cost of piping system. Costs of material and labor for main water supply and return piping, material and labor for module inlet and outlet manifold and feeder line, fill and bypass lines, valving, expansion joints, controls, and storage tanks are included.

10. Cost of condensers and installation

The annualized cost for the cooling system investment is equal to the capital cost multiplied by the fixed charge rate. The capital cost was obtained by summing up the 10 costs enumerated above.

5.2.2 Cooling System Penalties and Operating Costs

The plant equipped with a dry tower cooling system will incur cost penalties due to the fact that power output is reduced at elevated ambient temperature. A requirement for supplemental power will occur whenever the turbine output is below its design load at the busbar. This requirement for supplemental power will require additional expenditures for capacity and energy.

Capacity penalty is the cost of providing the capability to obtain the power that is lost due to the poor performance of dry cooling towers during hot ambient conditions. Other than purchasing excess capacity from other utilities, the simplest method is to erect a gas-turbine on site to provide the power during hot peaking conditions. A second method is to charge this capacity at the price of the next base loaded plant to be built in the system. The rationale here is that the next plant in question will underperform. Another method is to expand the plant under consideration to supply the loss in power. This study uses a cost of $100/KWe for installed gas turbine capacity and $500/KWe for installed capacity of a new plant.

Another capital expense arises from the fact that steam turbines for dry cooling towers are designed with slightly more steam flow than

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conventional turbines. This is due to the fact that higher back pressures are experienced and the exhaust flow area is decreased. The modified conventional 1000 MWe turbine uses approximately 73,000 lb/hr of additional steam. The steam supply system could be expanded to provide this at a cost of about $750,000. For the high back pressure turbine, an additional 513,000 lb/hr of steam is needed and would cost approximately $5.4 million for the steam generator.

Energy penalty is the cost of producing that electrical energy that is lost due to poor dry cooling tower performance. It was assumed that gas turbine generated energy would cost 40 mills/KW-HR, but at ambient temperatures below 82°F energy could be bought from the system at 20 mills/KW-HR. This type of energy penalty is referred to as "40/20" on subsequent tables and figures. If the energy penalty is assessed on building the next plant slightly larger, a cost of 10 mills/KW-HR is used regardless of ambient temperature. This type of energy penalty is referred to as "10/10" on subsequent tables and figures.

Special consideration must be given to penalties due to cooling system auxiliaries. This pertains to the power drawn by the fans and the recirculating pumps. This auxiliary power reduces the power available at the bus-bar for the load demand, and its cost is considered as an additional penalty cost. There exist 2 ways to supplement the auxiliary power required to power the fans and the circulating pumps. The first way is to consider the auxiliary power to be a penalty loss similar to loss of capability at high temperature. Thus, the auxiliary power can be drawn from the same source as the loss in capability at high temperatures with the corresponding charges for capacity and penalty. The second way is to recognize that the auxiliary power requirement would be of long duration and would be required even at low ambient temperatures. In this case the base plant capacity is expanded to supply the required auxiliaries. In such a case the capital and energy charges of the auxiliaries will use base plant cost factors.

There exist several considerations unique to dry tower application which will influence the choice of power for cooling system auxiliaries. If the yearly load demand is such that the plant will operate in the part load mode for a fraction of the year, the auxiliary power can be generated without plant expansion. For example, when the yearly load profile is 100 percent load for summer months and 75 percent load for the rest of the year, the auxiliary power can be provided at the 75 percent load requirement by simply overfiring the existing plant such that the power generated would be the auxiliary plus required bus-bar power. The cost penalty for this case will not include expanded plant capacity capital cost but will include incremental fuel cost that is charged for generating the auxiliary power. For the full load summer period, the auxiliary power penalty can be charged using gas turbine cost factors.

Another factor which influences the choice of the source for auxiliaries is the potential for fan control. In dry cooled systems approximately 75 percent of the auxiliary power requirement is for the fans, and the other 25 percent is the water pumping power. As the ambient temperature decreases, the performance of the dry tower increases and the back pressure is reduced. However, below a back pressure of about 5 in. Hg absolute the heat rate curve for a high back pressure turbine is almost flat, and little gain in power output is achieved with the reduction in back pressure. Thus, it would be more economical to maintain a constant back pressure and reduce fan power as the ambient temperature is reduced. A constant back pressure is reached below which the extra turbine power gained from a decrease in back pressure is less than the power saved by reducing the auxiliary fan power. A typical curve of fan-controlled power reduction as a function of ambient temperature is given in Figure 5.1. This figure shows that fan control begins at an ambient temperature of 73°F with the fan power decreasing rapidly with a further decrease in ambient temperature. At a temperature of 50°F the required fan power is only 10 MWe as compared to the design requirement of 25 MWe. This potential for fan control is unique to dry towers using non-conventional turbines. This behavior is contrary to conventional turbines with wet towers in which the reduction in back pressure as the ambient temperature decreases is used as a means to increase power production.

The above behavior would indicate that considering the source for auxiliary power requirement as identical to the source for loss in capacity at high ambient temperature (i.e., gas turbines) has economic merit by saving the cost for increased incremental base plant capacity. This method of accounting for auxiliary penalty, which uses gas turbine generated power, was used throughout this work. In some cases, however, a comparison was made between results obtained with the above accounting method and the method which provides for increased base plant capacity for auxiliaries.

5.3 Optimization Methodology

The general flow diagram for the optimization procedure is given in Appendix C. The steps in the optimization codes are as follows:

1. Input

2. Design the cooling system, i.e., dry tower, circulating water system and condenser on the basis of a combination of design variables

3. Calculate capital cost of the system

4. Determine plant performance with the change in annual ambient temperature over the annual cycle

5. Calculate capital and energy costs for cooling system auxiliaries and loss in generating capacity, employing fan control and extra firing when advantageous

SITE = CASPER
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20***

TUBE CONFIGURATION = 6R2P *
CAPACITY FACTOR = .914
SUMMER HOURS NOT EXCEEDED = 10 **
TUBE LENGTH (FT) = 80
ITD (^{o}F) = 49.9
RANGE (^{o}F) = 28
HOURS ABOVE 82^{o}F AMBIENT = 440 *

* See page 51 for definition
** See page 51 for definition
*** See page 32 for definition

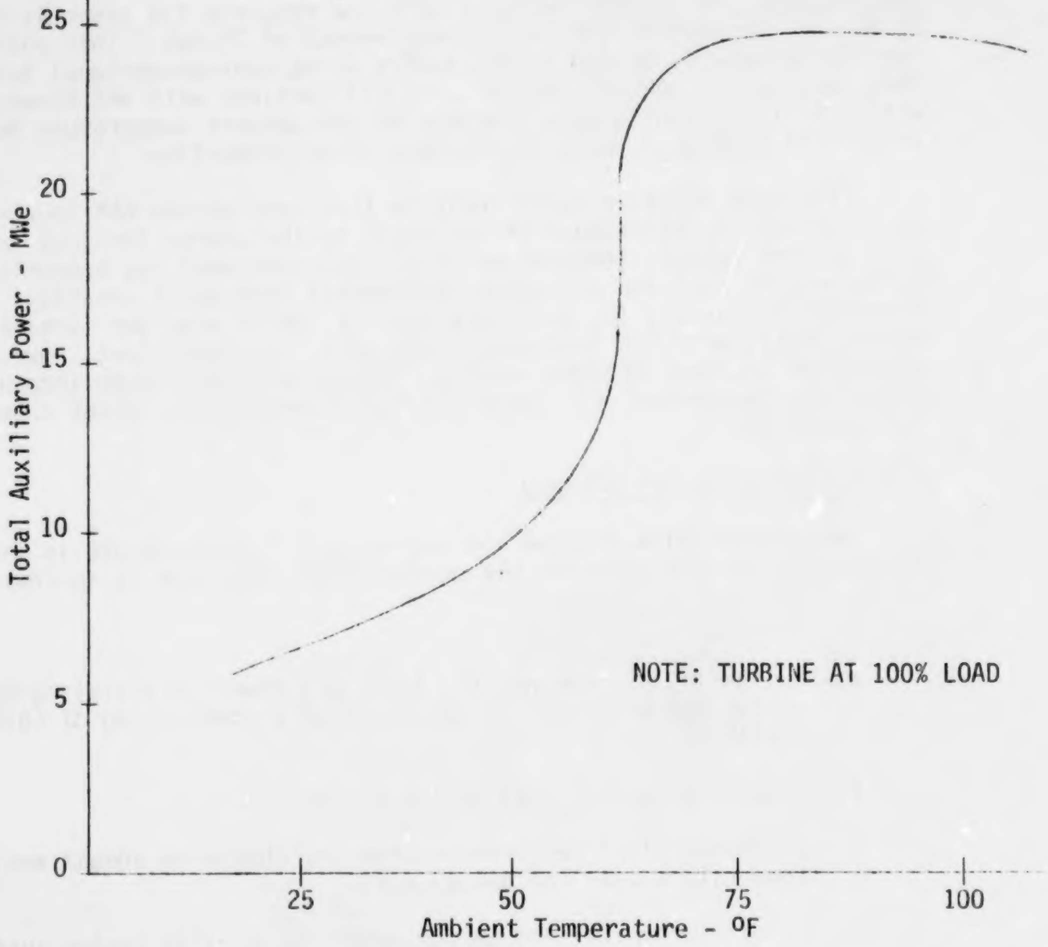


Figure 5.1. Fan Control Curve.

6. Calculate total fuel cost
7. Determine total incremental bus-bar cost of the cooling system
8. Employ the box multicomponent optimization search scheme to generate a new set of design variables that will lead to total cost
9. Stop when the combination of variables that will result in lowest total cost has been found
10. Print the optimum results

The first step involves the determination of the program input. This is described in detail in Appendix H.

The second step involves the selection of random combinations of design variables consisting of heat load, ITD, range, TTD, tube length, and number of modules. The program iterates to find the right approach velocity which will satisfy the heat transfer characteristics of the modules. The module design is described in Section 4.4. A suitable fan design is selected and total fan power is calculated.

The third step involves the design of the condenser, interconnecting piping, pumping power, pumps, storage tank controls and valves, and all other auxiliary equipment of the cooling water system. The capital cost of all the components is then evaluated as well as the costs for shipping, structures and foundations, erection and construction, and electrical connections.

The fourth step involves the evaluation of the plant performance with the changes in the ambient temperatures. The highest ambient temperature for penalty calculations is determined from the annual temperature duration curve. In most calculations, the temperature at the site which was equaled or exceeded 29 hours a year (equivalent to 1 percent of the 4 warmest months) was taken as the highest ambient temperature. For each combination of ambient temperature and the time occurrence (number of hours), the program calculates plant performance by matching heat rejected from the tower with the heat load of the turbine. Heat transfer calculations are performed to find the turbine back pressure for each given ambient temperature. At each ambient temperature a check is made to determine whether fan control is economical and whether the demanded load is less than 100 percent. If demanded load is 100 percent of the design load for the turbine and the turbine output is less than this load, the energy penalty is calculated. If the demanded load is below 100 percent, a search is made for a turbine operating point which produces the demanded load plus auxiliary power. In addition to the fuel consumption energy penalty, the replacement capacity penalty is calculated.

After evaluating the performance over the entire year, the program calculates and sums the fuel cost, energy penalty cost, replacement capacity cost, capital and operating costs, the total annual cost and the total incremental bus-bar cost of the cooling system. The program then utilizes the "Box" multicomponent optimization search scheme, generates a new set of independent variables and repeats the entire process. The calculation stops when a combination of design variables is found which leads to the lowest total evaluated cost.

As was evident in the analysis, there exist many combinations of the design variables which will result in a cooling system with identical total annual cost. Since the cost is a function of 6 variables, it cannot be represented simply as a graph on a 2-dimensional plot. The effect of design variables on the cost was investigated by tabulating all the cost points for the combinations of all variables. No graphs can be plotted since the functional variation on a 2-dimensional plot is not easily discernible.

Figures 5.2 to 5.4 show how the annual cost may vary with the ITD. The points on the figures are the annual costs for cooling systems designed with a random combination of design variables. Each point represents the annual cost of the cooling system with a different combination of ITD, range, fan power, number of modules, TTD, and ambient temperature. No meaningful curves can be plotted through the points. For any given fixed ITD, the annual cost may vary as much as \$3-4 million (vertical distance between high and low points), depending on the combination of design variables. It is evident that the points are distributed in a domain of ITDs in which the cost reaches a minimum but no single point is the absolute minimum; there exist several points with different ITD and identical cost. This indicates that other design variables, such as fan power and range, may have compensating effects on the total annual cost. Figures 5.2 to 5.4 indicate that the ITD cannot serve as the only independent variable that will determine the optimum design of a cooling system. For example, Figure 5.3 shows the cost analysis for the Atlanta site with the lowest cost as \$15.6 million. The lowest cost corresponded to an ITD of 49.5^{o}F. However, for that ITD there exist other points which show the cost to be \$16.6 million. The difference stems from slight changes in design ambient air temperature, temperature range, condenser TTD, number of tower modules and fan power.

Figures 5.5 and 5.6 show the variations of annual cost with range/ITD for the Phoenix site. The ITD was kept fixed at 60^{o}F for Figure 5.5 and 30^{o}F for Figure 5.6. Large variations in cost are evident from these figures. The lowest point tends to be between ratios of 0.4 and 0.6. However, for a given range/ITD ratio the price can vary by about \$1 million (vertical distance on the graphs). This indicates that no single optimum range/ITD ratio exists but that the ratio is a function of the other independent design variables.

SITE = CASPER
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = 1.50
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
ITD (°F) = --
RANGE (°F) = --
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

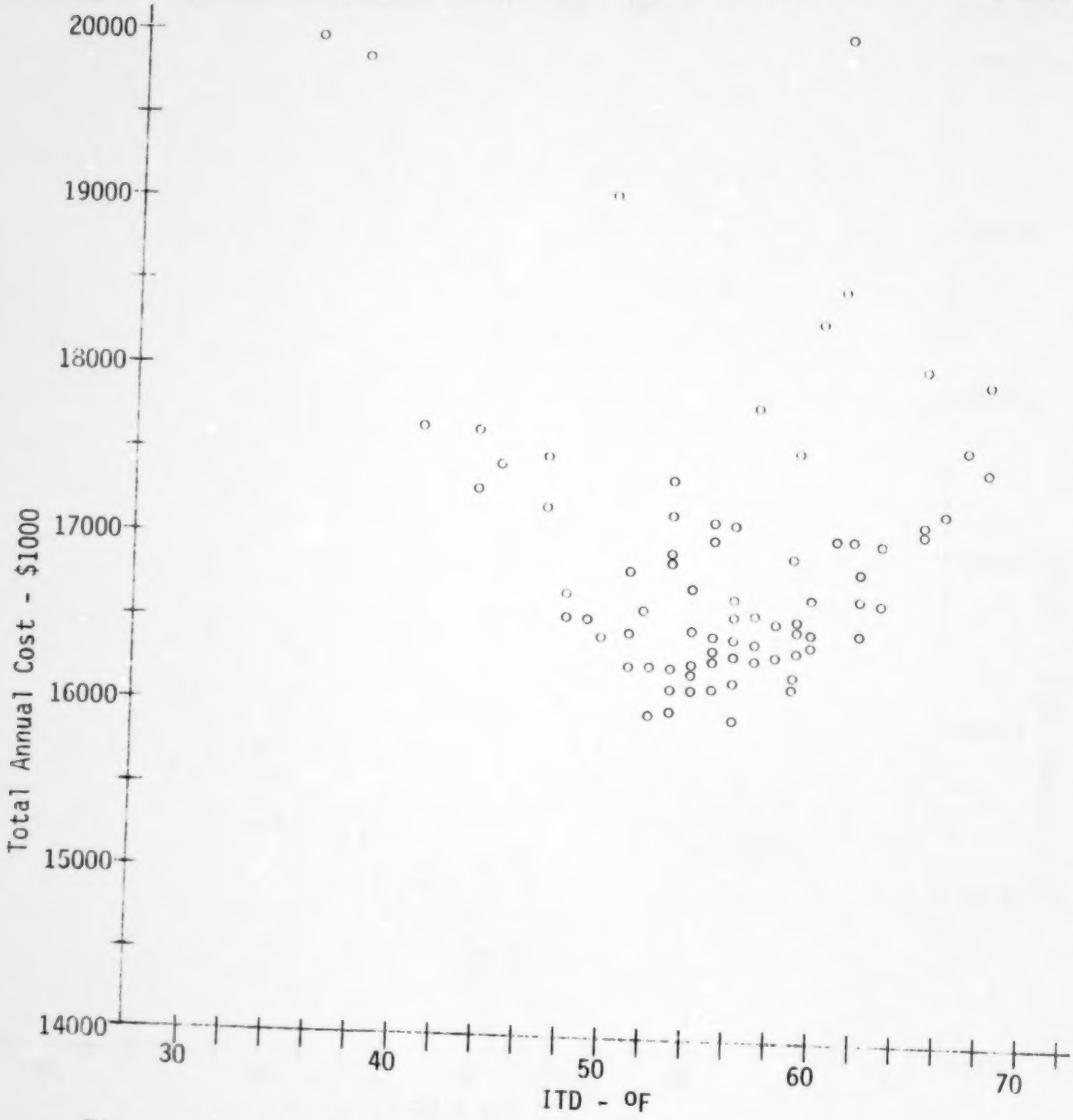


Figure 5.2. Total Annual Cost for a Nominal 1000 MWe Fossil-Fueled Plant at Casper, WY.

SITE = ATLANTA
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
ITD (°F) = --
RANGE (°F) = --
HOURS ABOVE 82°F AMBIENT = 733
TOTAL GENERATION (MW-HR) = 6,570,000

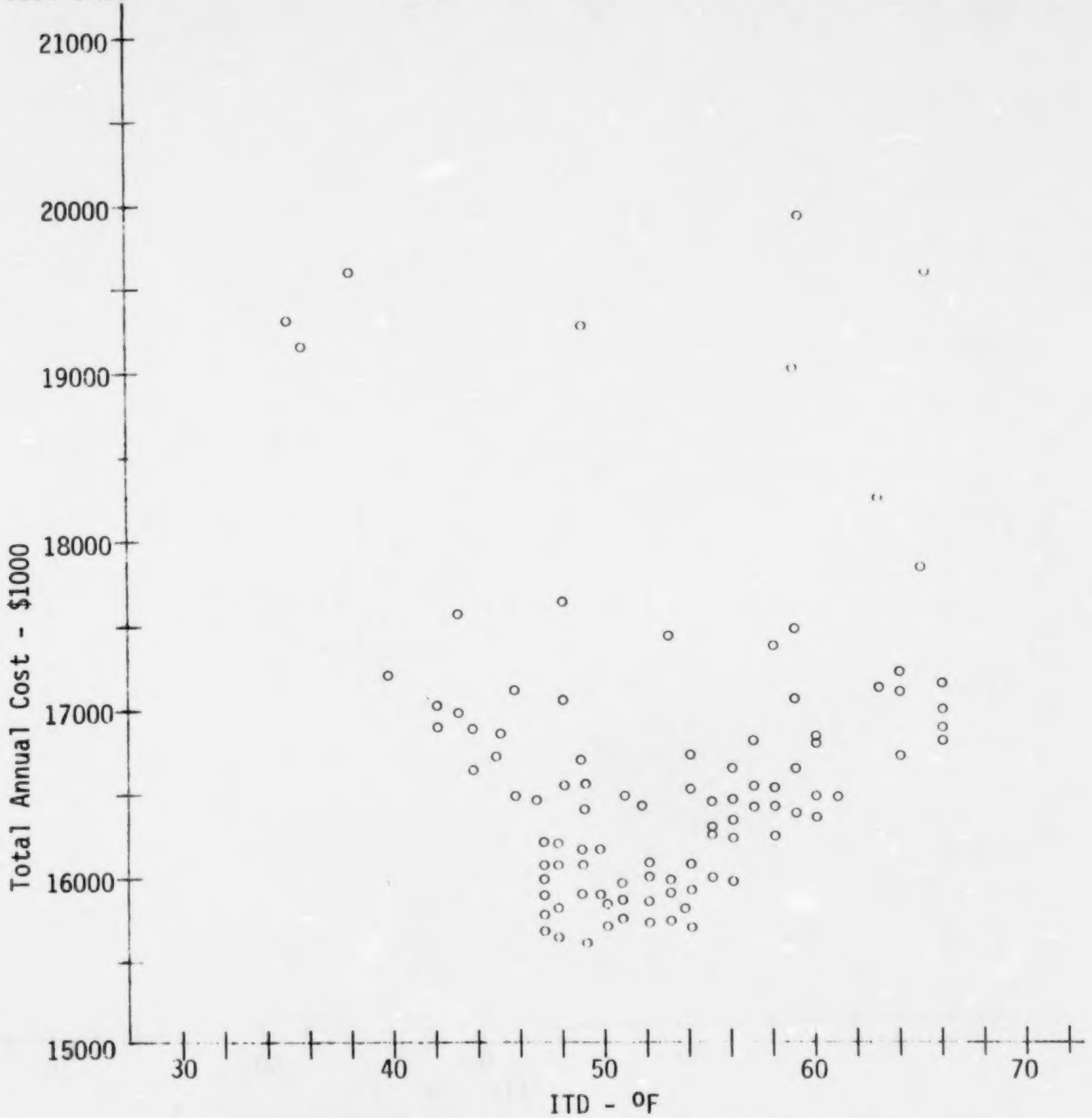


Figure 5.3. Total Annual Cost for a Nominal 1000 MWe Fossil-Fueled Plant at Atlanta, GA.

SITE = PHOENIX
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
ITD (°F) = --
RANGE (°F) = --
HOURS ABOVE 82°F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

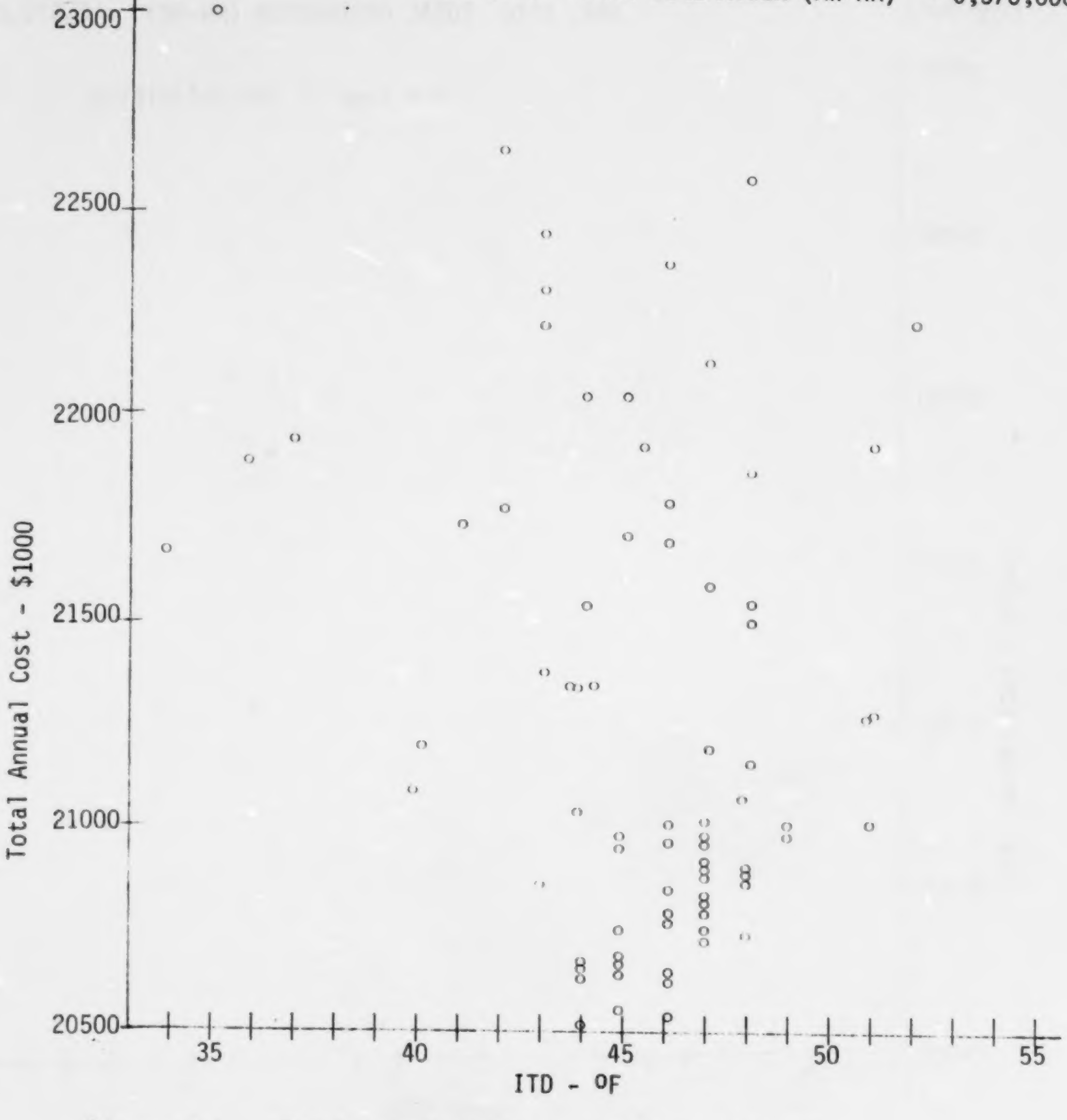
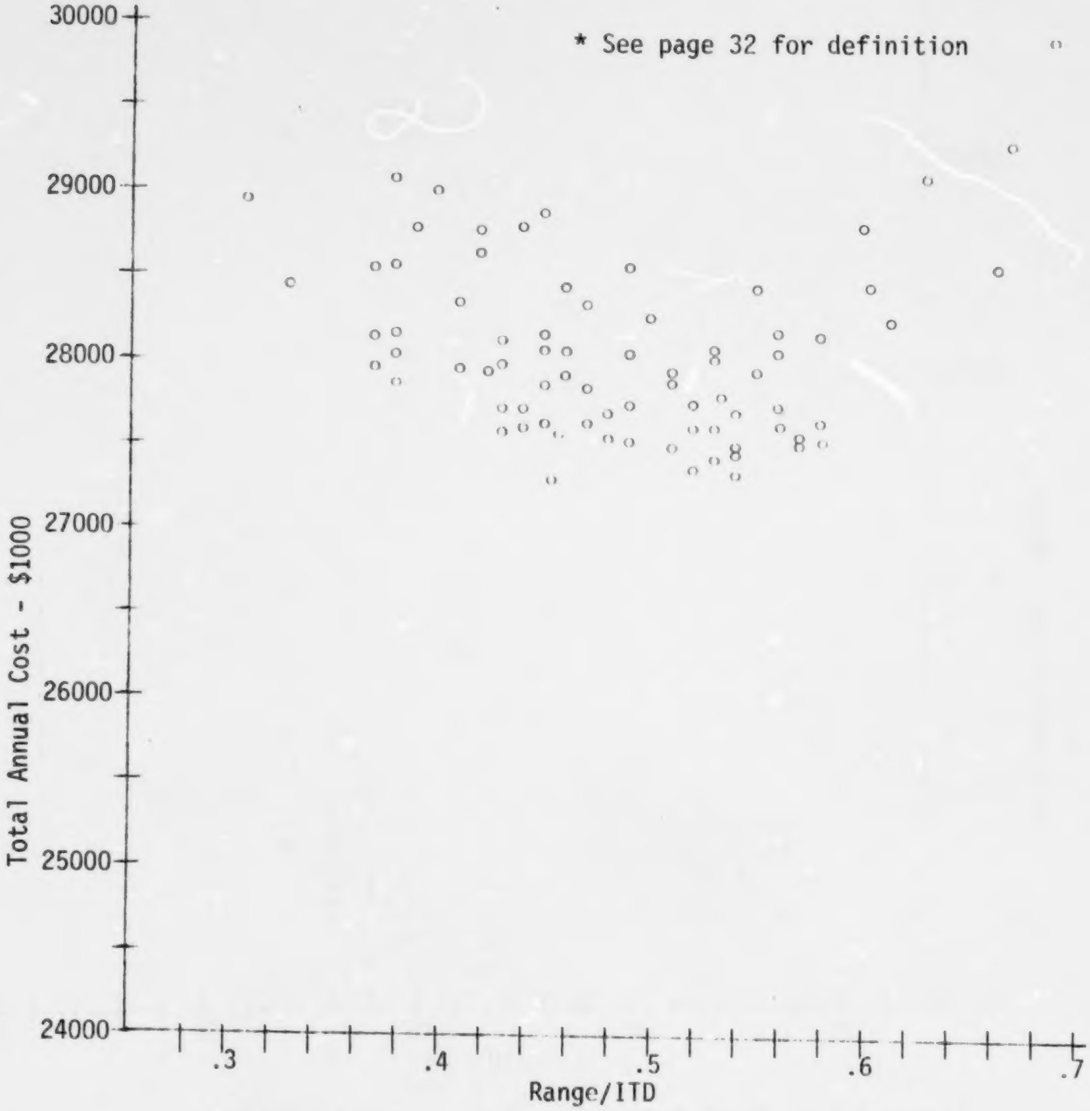


Figure 5.4. Total Annual Cost for a Nominal 1000 Mwe Fossil-Fueled Plant at Phoenix, AZ.

SITE = PHOENIX
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10 *
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
ITD (°F) = 60
RANGE (°F) = --
HOURS ABOVE 82°F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000



* See page 32 for definition

Figure 5.5. Total Annual Cost for a Nominal 1000 MWe Fossil-Fueled Plant at Phoenix, with ITD fixed at 60°F.

SITE = PHOENIX
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
TUBE LENGTH = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
ITD (^{o}F) = 30
RANGE (^{o}F) = --
HOURS ABOVE 82^{o}F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

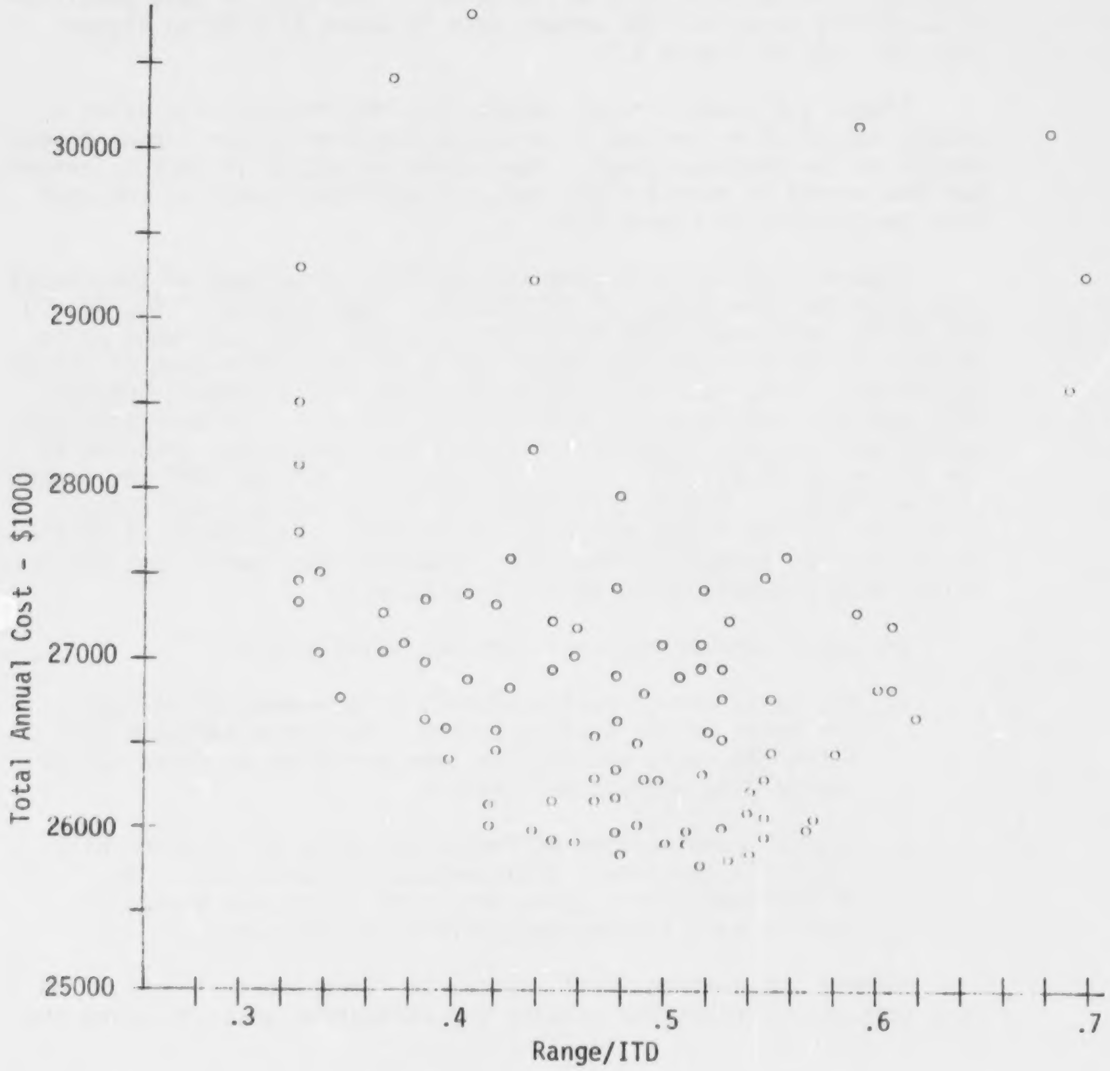


Figure 5.6. Total Annual Cost for a Nominal 1000 MWe Fossil-Fueled Plant at Phoenix, with ITD fixed at 30^{o}F.

Figures 5.7 and 5.8 show the effect of auxiliary power pumping and fan power on the total annual cost. Wide variation of cost with auxiliary power is evident with no specific trend. Figure 5.7 is for the Phoenix site using a gas turbine for supplying loss in capacity (capacity cost $100 KWe, energy cost 40/20 mills/KW-HR). The figure shows that the total annual cost is sensitive to the auxiliary power; deviations of ± 3 MWe from the lowest point result in an increase of about $0.5 million. Figure 5.8 is for the Phoenix site using an expanded plant for supplemental capacity (capacity cost $500/KWe, energy cost 10/10 mills/KW-HR). The cost is less sensitive to auxiliary power but the annual cost is about $3 million higher than the cost of Figure 5.7.

Figure 5.9 shows similar results for the Phoenix site using a module design of 4 rows and 2 passes as compared to the 6-row, 2-pass design in the previous graph. Again wide variation in cost is evident but the spread is over a wider range of auxiliary power as compared with the results of Figure 5.7.

Figures 5.10 and 5.11 show the possible variations of the annual cost with the tube length of the module. Tube lengths of 40, 60, 70 and 80 ft. were used. The variation in annual cost can range up to $6 million for a fixed tube length and a random combination of design variables. These cost variations are based on ITD ranging between 30°F and 70°F and range/ITD between 0.35 and 0.65. In observing the variations in cost, it was evident that the lowest cost occurred in the ITD range of 41-43°F. For ITDs closer to 30°F or 70°F the annual cost was higher. Figure 5.11 shows the variation in total annual cost with the ITD fixed in a range of 41-43°F. Variations of up to $3 million are evident in the cost. However, the lowest cost was obtained with a module using 80-ft. long tubes.

Two major conclusions stem from the above results:

1. The total annual evaluated cost is dependent on all the variables of the cooling system. No single variable dominates the cost, and setting some variables as fixed values can lead to non-optimal results.

2. Several combinations of design variables exist which will result in the lowest total annual evaluated cost. No unique combination gives this cost since some variables tend to have compensatory effects on the cost.

Optimal combinations will lead to the lowest annual cost. The next section describes the results and parametric analysis using the optimal results.

SITE = PHOENIX
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 10
ITD (^{o}F) = --
RANGE (^{o}F) = --
HOURS ABOVE 82^{o}F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

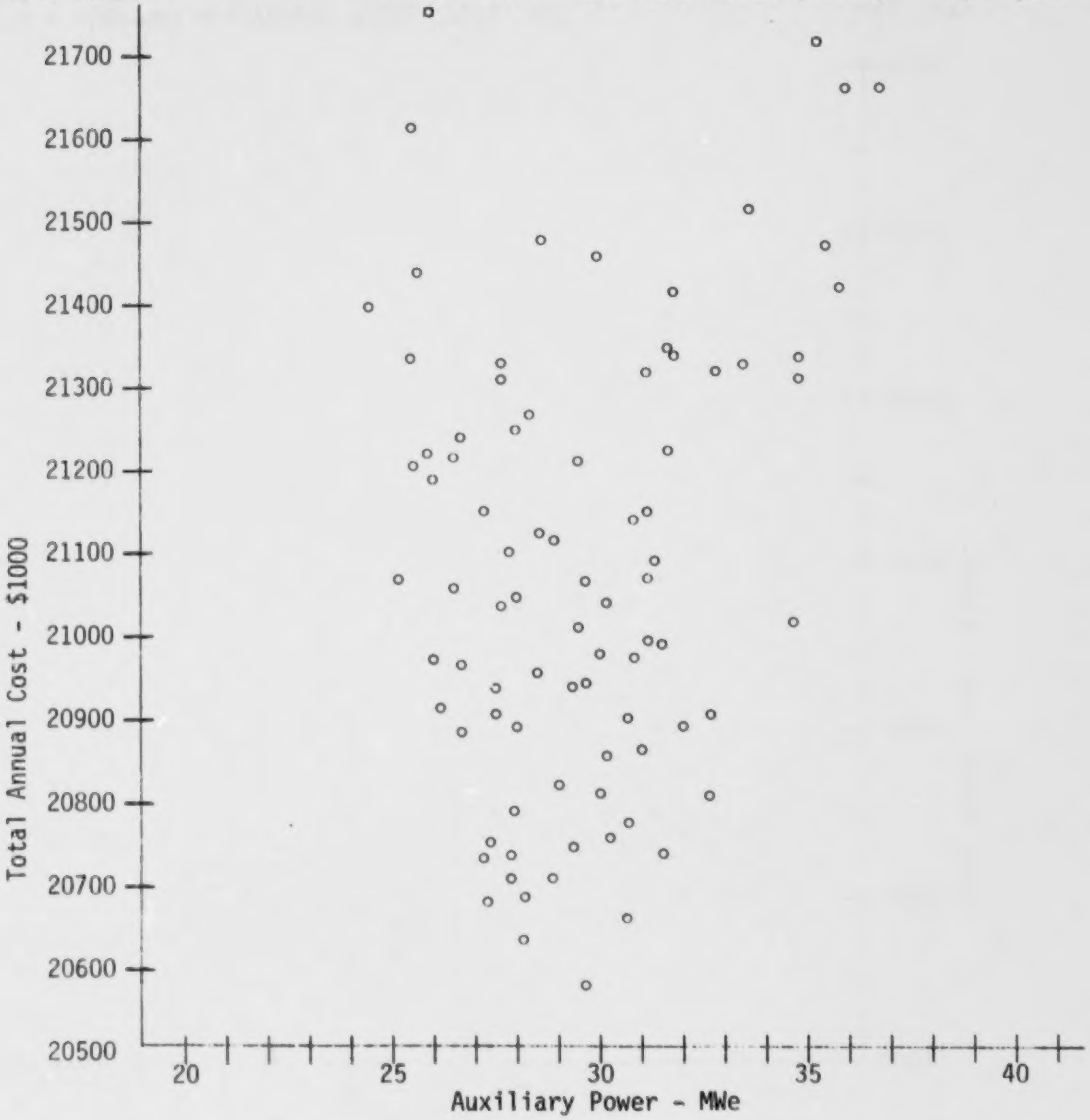


Figure 5.7. Cost for a Nominal 1000 MWe Fossil-Fueled Plant at Phoenix, at $100/KWe: 6-Row, 2-Pass Tube Configuration.

SITE = PHOENIX
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
ITD (^{o}F) = 40
RANGE (^{o}F) = --
HOURS ABOVE 82^{o}F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

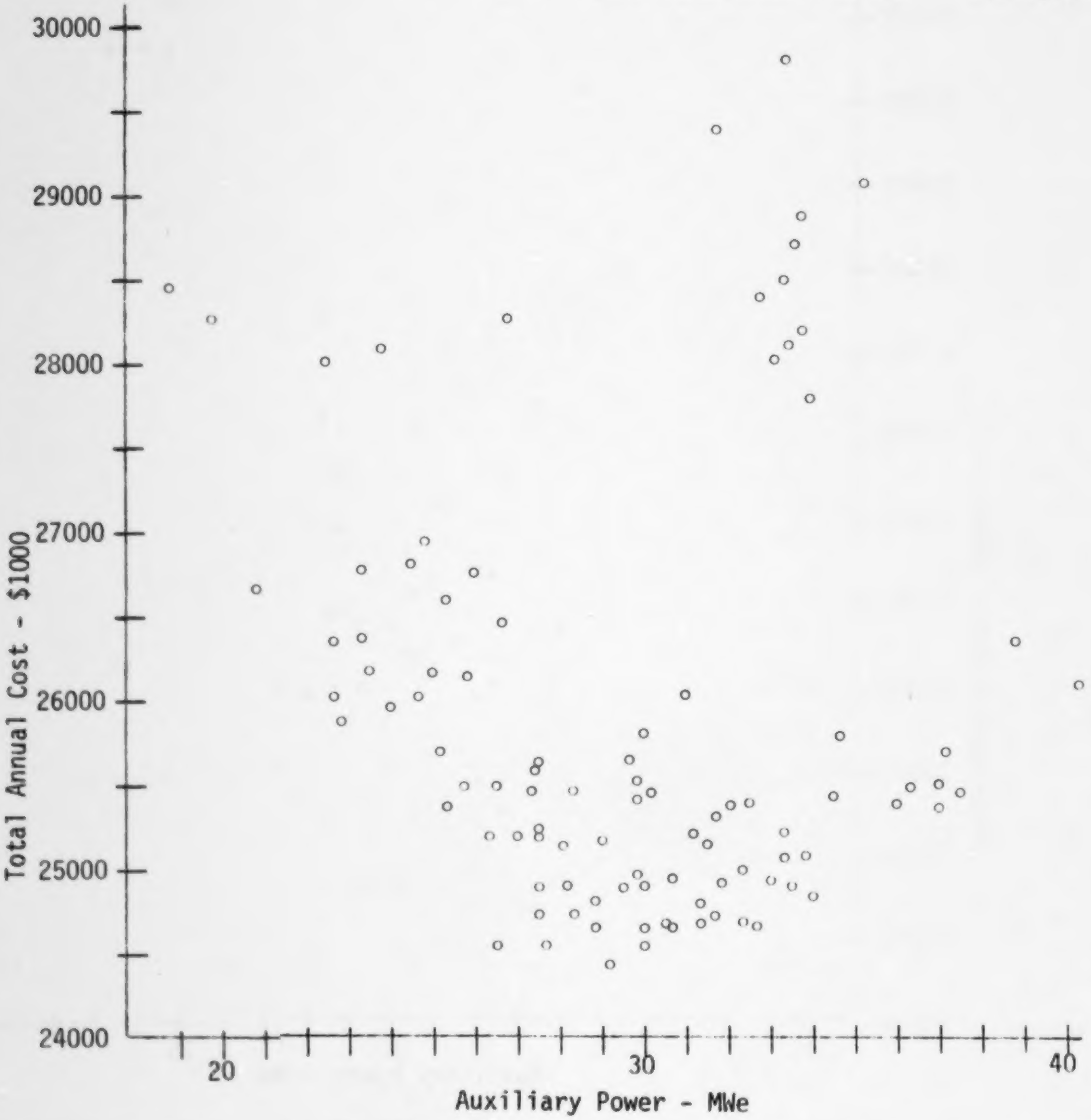


Figure 5.8. Cost for a Nominal 1000 MWe Fossil-Fueled Plant at Phoenix at $500/KWe: 6-Row, 2-Pass Tube Configuration.

SITE = PHOENIX
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/HW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 4R2P
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 10
ITD (^{O}F) = --
RANGE (^{O}F) = --
HOURS ABOVE 82^{O}F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

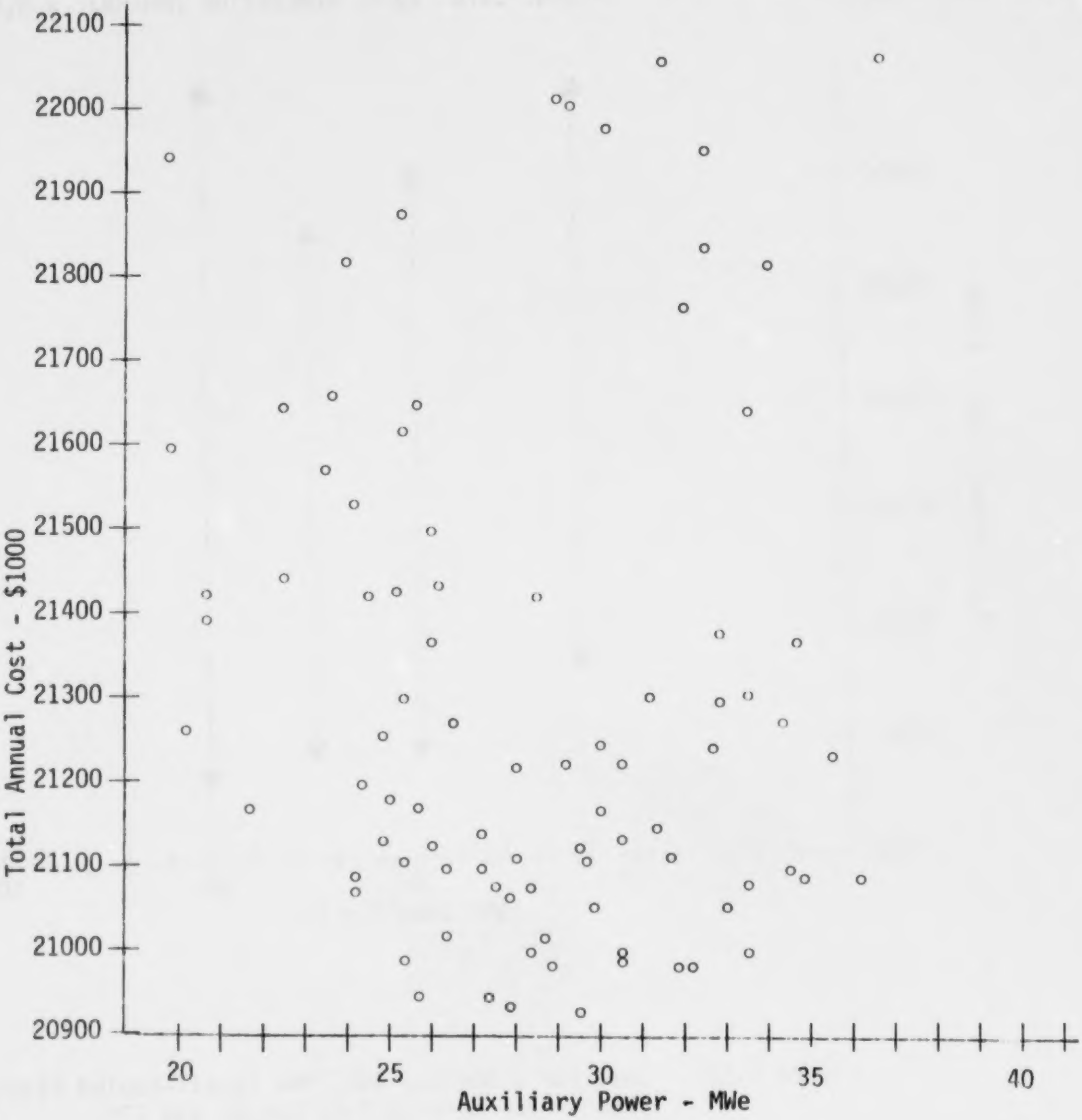


Figure 5.9. Cost for a Nominal 1000 MWe Fossil-Fueled Plant at Phoenix at $100/KWe: 4-Row, 2-Pass Tube Configuration.

SITE	= PHOENIX	TUBE CONFIGURATION	= 6R2P
CONDENSER TYPE	= SURFACE	TUBE LENGTH (FT)	= --
TURBINE TYPE	= MOD.CONV.	CAPACITY FACTOR	= .75
FIXED CHARGE RATE	= .20	SUMMER HOURS NOT EXCEEDED	= 29
FUEL COST ($/MMBTU)	= .75	ITD (^{o}F)	= 30-70
CAPACITY COST ($/KWe)	= 500	RANGE (^{o}F)	= --
ENERGY COST (MILLS/KW-HR)	= 10/10	HOURS ABOVE 82^{o}F AMBIENT	= 2760
COST BASE	= JAN. 1976	TOTAL GENERATION (MW-HR)	= 6,570,000

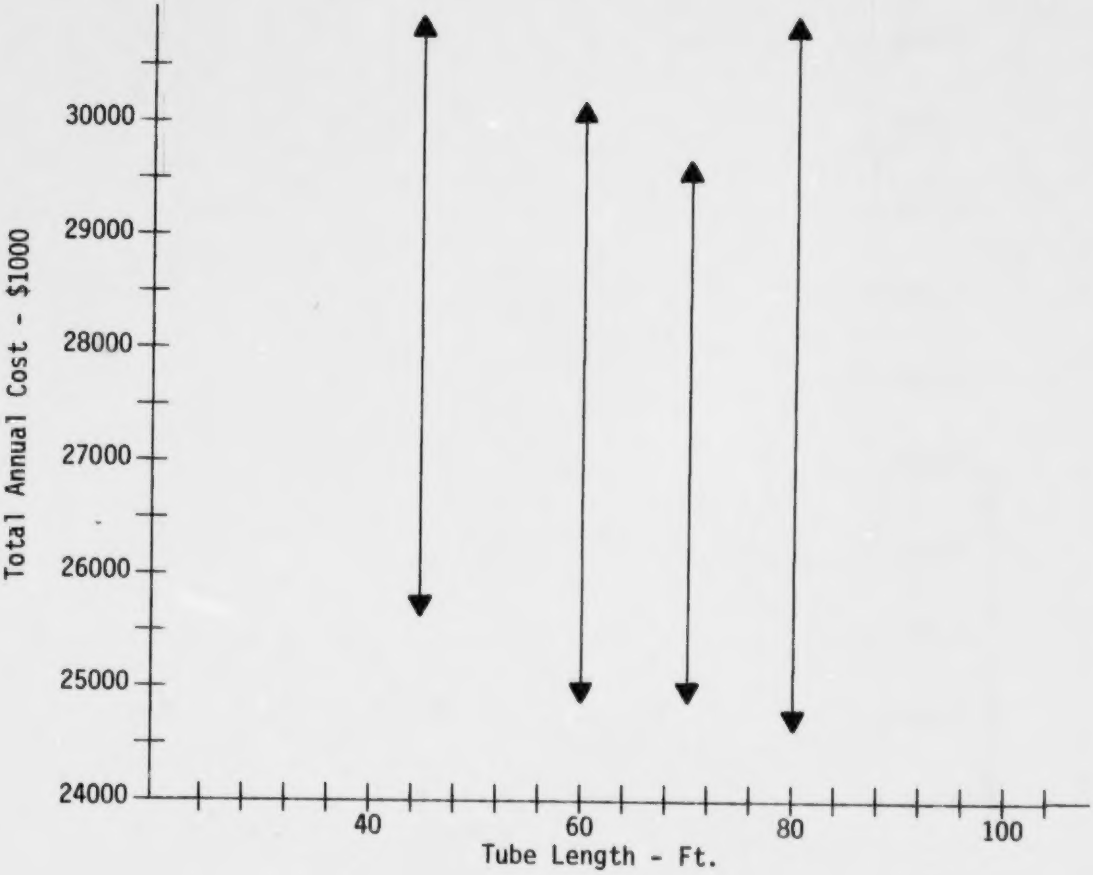


Figure 5.10. Cost for a Nominal 1000 MWe Fossil-Fueled Plant at Phoenix for Varying Tube Length and ITD.

SITE = PHOENIX
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
TUBE LENGTH (FT) = --
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
ITD (°F) = 41-43
RANGE (°F) = --
HOURS ABOVE 82°F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

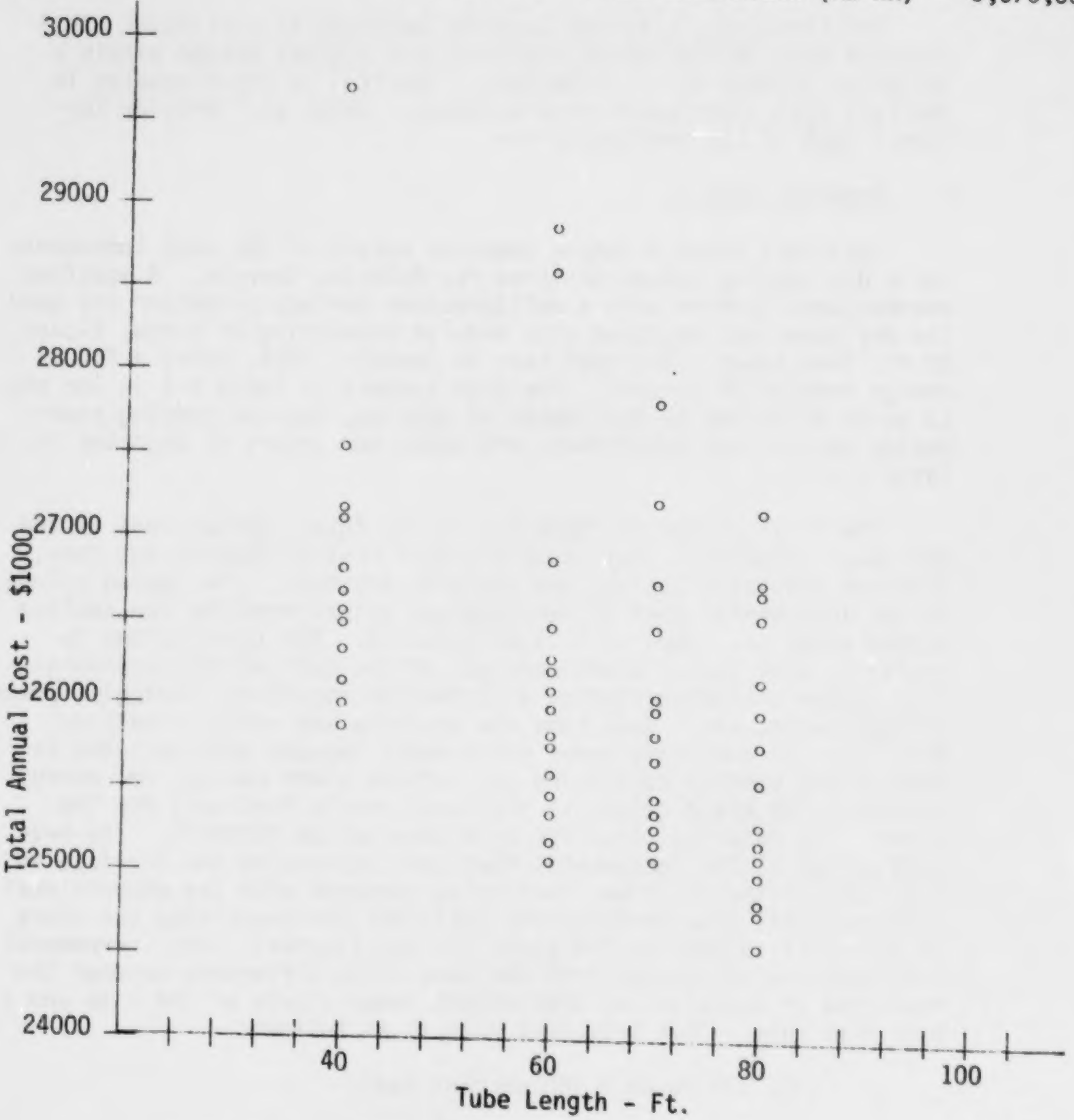


Figure 5.11. Cost for a Nominal 1000 MWe Fossil-Fueled Plant at Phoenix for Varying Tube Length and Fixed ITD.

SECTION 6

RESULTS AND DISCUSSION

The final result in the computer analysis is a printout of 13 possible best designs which represent the optimal design within a variation in cost of ± 0.5 percent. Implicit in these results is the fact that there exist several designs which will provide the lowest cost of the cooling system.

6.1 Computer Output

Table 6-1 shows a sample computer output of the cost components for a dry cooling system designed for Atlanta, Georgia. A modified conventional turbine with a multipressure surface condenser was used. The dry tower was designed with modules consisting of 6-row, 2-pass, 80-ft. long tubes. The cost base is January, 1976, using a fixed charge rate of 20 percent. The cost summary in Table 6-1 is for the 13 cases differing in the number of modules, fan and pumping power, design ambient air conditions, and other parameters as depicted in Table 6-2.

The first column of Table 6-1 is the total capital cost of the dry tower structure. This cost includes cost of modules and fans, erection and installation, and support structure. The second column is the incremental cost of overhead and maintenance for the cooling system which was taken as 0.05 mills/KW-HR. The third column is entitled "pipe cost," which consists of the cost of the recirculating system including piping, distribution manifolds, controls, pumps, storage tanks, etc. Next come the capacity and energy penalties. Note that the auxiliary power requirement charges were included as part of the penalty cost using gas turbine plant capital and energy charges. The sixth column is the total yearly fuel cost for the plant. The base fuel cost for this case was $0.75/MMBTU. The seventh column is the incremental fuel cost expressing the increase in fuel cost of the dry tower turbine as compared with the conventional turbine. This also includes the fuel cost for overfiring the plant at part load to provide the power for auxiliaries. This incremental fuel cost was calculated from the cumulative difference between the heat rate of the plant at the ambient temperatures of the site and a base heat rate. This base heat rate is as follows:

1. 8887 BTU/KW-HR @ 100 percent load.
2. 9021 BTU/KW-HR @ 75 percent load.
3. 9396 BTU/KW-HR @ 50 percent load.

TABLE 6-1. COST SUMMARY OF MECHANICAL DRAFT DRY COOLING TOWER SYSTEM

THE FOLLOWING SHOWS ANNUAL COSTS IN THOUSANDS OF DOLLARS FOR THE OPTIMIZED DESIGNS OF THE BOX COMPLEX

	1 TUBE MODULE COST	2 HEAT REJECT O+M	3 PIPE COST	4 CAPC PEN.	5 ENERGY PEN.	6 ANNUAL FUEL COST	7 INCR. FUEL COST	8 COND. COST	9 WATER RECVRY TURB.	10 ELEC. SUB-STAT.	11 INTRST DURING CONSTR	12 MILL PER KWH	13 TOTAL COST
1	4961.0	328.5	1605.4	1371.3	3755.2	45369.7	1144.9	782.0	0.0	136.8	916.2	2.391	15711.3
2	5043.9	328.8	1681.4	1809.2	3616.7	45352.9	1128.1	790.7	0.0	141.9	937.0	2.388	15687.6
3	5232.6	329.3	1729.7	1707.1	3350.3	45339.2	1114.4	826.7	0.0	143.6	969.9	2.377	15613.6
4	5504.0	329.9	1819.8	1592.3	3072.1	45328.9	1104.0	862.6	0.0	145.8	1017.9	2.383	15658.5
5	4831.5	328.5	1513.0	1726.0	3906.8	45389.2	1164.4	766.4	0.0	139.6	888.1	2.386	15674.2
6	5320.0	329.5	1740.5	1695.9	3335.0	45339.3	1114.4	813.3	0.0	146.7	980.5	2.388	15685.9
7	5251.6	329.9	1755.2	1668.3	3299.0	45356.6	1131.8	844.4	0.0	151.0	978.3	2.377	15619.5
8	5213.6	328.8	1727.5	1747.4	3430.3	45332.6	1107.8	814.1	0.0	138.0	965.2	2.387	15682.8
9	4828.8	328.4	1546.2	1927.2	3905.9	45385.9	1161.1	768.7	0.0	138.4	891.9	2.391	15706.5
10	5108.7	329.3	1691.1	1769.2	3541.0	45359.5	1134.7	797.4	0.0	148.6	947.5	2.386	15677.5
11	5232.6	328.8	1647.4	1779.1	3544.3	45335.2	1110.4	770.1	0.0	142.6	955.1	2.392	15718.5
12	5504.0	329.8	1829.0	1597.8	3122.0	45331.4	1106.5	853.4	0.0	145.6	1017.8	2.392	15715.9
13	5369.5	329.5	1778.1	1643.5	3184.4	45330.6	1105.7	854.2	0.0	142.2	995.3	2.376	15612.4

* Note: for explanation of all costs, see Section 6.1.

TABLE 6-2. TOWER PARAMETER SUMMARY

											* PRES. DROP	
	DESIGN HEAT DUTY MMBTU/HR	TTD °F	MAX. BACK PRES. in.Hg	FAN HP	FAN MW	PUMP MW	WRT MW	AUX. MW	RNG/ ITD	ITD °F	AIR SIDE in.H_2O	TUBE SIDE psi
	1	2	3	4	5	6	7	8	9	10	11	12
1	4717.8	5.0	8.4	159.	17	6	0	23.0	.53	53.2	.63	9.3
2	4735.6	5.0	8.1	176.	19	6	0	24.8	.53	51.5	.66	9.4
3	4717.5	5.0	7.7	166.	19	6	0	25.3	.52	49.3	.65	10.0
4	4717.5	5.0	7.2	160.	19	7	0	26.0	.51	47.1	.63	10.2
5	4717.4	5.0	8.6	172.	18	5	0	24.1	.54	53.7	.67	9.3
6	4727.5	5.0	7.5	178.	20	6	0	26.5	.54	48.6	.67	9.4
7	4717.4	5.0	7.3	191.	22	6	0	28.3	.52	47.7	.70	10.5
8	4733.0	5.0	8.0	149.	17	6	0	23.2	.51	50.7	.60	9.7
9	4717.7	5.0	8.6	177.	18	5	0	23.6	.54	53.9	.66	9.3
10	4721.4	5.0	7.7	199.	21	6	0	27.4	.55	49.9	.70	9.4
11	4762.1	5.0	8.0	170.	17	5	0	25.0	.56	51.0	.66	8.2
12	4753.2	5.0	7.2	159.	19	7	0	25.9	.51	47.3	.63	10.2
13	4718.2	5.0	7.5	158.	18	7	0	24.7	.50	48.4	.61	10.4

Note: All parameters are for the entire dry cooling tower, except for column 4 which is the horsepower per fan.

These heat rates correspond to the conventional steam turbine at 3.0, 2.0, and 1.0 in. Hg absolute back pressure, respectively.

The eighth column is the total cost of the condenser including material and installation. This is followed by the cost items of the water recovery turbine when jet condensers are employed. The tenth column is the cost of electrical work for connecting the power to the fans and uses a portion of the transformer switch yard. The interest during construction is the last item before the mills/KW-HR and the total annual evaluated cost items. Mills/KW-HR is the total annual cost divided by total power produced; this expresses the total annual evaluated cost of the dry cooling system of the plant per unit of power produced.

Table 6-2 shows the design conditions corresponding to the 13 designs shown in Table 6-1. Note that the TTD of the surface condenser was optimized at the lowest allowable TTD. Column 3 of Table 6-2 shows the possible variation in maximum back pressure for different designs with identical cost. The back pressure range is between 7.2 and 8.6 in. Hg absolute. The column entitled ITD shows the optimal ITD for the various 13 designs. The results in this column show also the variation in the design ITD for an optimum. In this case the range of ITD is between 53.9 and 47.1^{o}F. Additional output showing the design information for the optimal case is given in Appendix E.

A demonstration of cost breakdown of the cooling system components is given in Table 6-3 which shows the optimum cost for Casper, Wyoming. This table shows the piping system as a major cost component in the dry tower due primarily to the requirement of distribution manifolds and general field labor.

A parametric study was prepared to evaluate the effect of design and economic factors on the dry tower annual evaluated cost. As was shown in Tables 6-1 and 6-2, the optimal analysis results in a complex of 13 best designs, all within ± 0.5 percent tolerance. Any of the alternate 13 best designs can serve as the optimal design. The results of the parametric study are presented in a tabular form as shown in Tables 6-4 through 6-24. The design and cost information is grouped in the table for easy identification and interpretation of the results.

Few items in the parametric tables (see Tables 6-4 - 6-24) require explanation. The tube configuration item, first line on the right side of the table, corresponds to the number of rows and number of passes of the tube modules. This is designated with 2 digits and 2 letters. The letter R refers to rows and the letter P refers to passes. The symbol 6R2P refers to a tube module configuration of 6 rows and 2 passes. The item "SUMMER HOURS NOT EXCEEDED," also placed on the right side of the table, pertains to the number of hours on the temperature probability curve of the site that corresponds to the maximum temperature used for the calculation of capacity and energy penalties. The numbers of hours

TABLE 6-3. COST FACTOR BREAKDOWN IN MILLIONS OF DOLLARS*

Cost of tube modules	$ 15.500	
Cost of fans and motors	4.280	
Cost of shipping	0.745	
Cost of structure	2.345	
Cost of erection and installation	1.930	
SUB-TOTAL (dry tower and cooling air)	$ 24.800	$ 24.80
Cost of condenser	$ 4.140	
Cost of piping, manifolds, and pumps	4.050	
Cost of controls, valving	2.760	
Cost of storage tank and pit	1.330	
Cost of shipping	0.170	
SUB-TOTAL (cooling water)	$ 12.450	$ 12.45
Cost of added steam supply	$ 0.750	
Cost of electrical substation & cabling	0.700	
Cost of auxiliary wet tower	0.300	
SUB-TOTAL (energy & capacity penalties)	$ 1.750	$ 1.75
Cost of interest during construction (11.9 percent of sum of above subtotals)	$ 4.640	$ 4.64
TOTAL CAPITAL COST		$ 43.64

* Cost base: January 1976

and the corresponding maximum temperature are selected somewhat arbitrarily by designers of cooling towers.

The total annual cost in thousands of dollars is the first item of the results in the body of the tables. This is followed by the major cost items of the dry cooling systems. Cost items such as interest during construction, cost of additional steam supply, etc. are not shown in the tables. The design variables of the optimal tower are shown in the third body of information on the lower part of each table. The item "MAX LOSS IN GENERATION (MWe)" shows the loss in capacity at the highest temperature combined with the total auxiliary power required.

6.2 Effect of Site on Cost of Dry Cooling

Table 6-4 shows the cost summary of dry cooling systems employed for power plants located at 5 sites within the continental U.S. Design and cost information is grouped in the table for easy identification and interpretation of the results. The tube configuration of the modules consists of 6 rows with 2 passes (6R2P), and the tubes are 30 ft. long. The highest ambient temperature used for penalty assessment was selected as the temperature that is not exceeded 29 hours during the summer.

Table 6.4 shows the strong effect which the location has on the cost of the dry cooling system. The annual cost of a dry cooling system located in Burlington, Vermont, is $7.5 million less expensive than a system located in Phoenix, Arizona. This is evident from the different weather conditions at the two sites. The Phoenix site has a maximum ambient temperature (occurring no more than 29 hours in the summer) of 109.5°F, whereas Burlington's similar maximum temperature is only 88.2°F. Furthermore, the Phoenix site has over 2760 hours when the temperature is above 82°F as compared with 176 hours in Burlington. Both the maximum temperature at the site and the area under the annual temperature duration curve affect the cost of the dry tower.

Table 6-4 indicates that the cost of piping is a major component in the cost of the dry tower. The cost of piping is about double the cost of the surface condenser. This stems from the fact that the large number of dry tower modules requires an extensive piping and distribution system.

6.3 Effect of Turbine Type

Table 6-5 shows the results of the analysis for plants employing either the high back pressure or the modified conventional turbine. Both the Casper and the Phoenix sites were studied. The results of Table 6-5 were computed with a fuel cost of $0.75/MMBTU. Table 6-5 shows that for this fuel cost the use of a high back pressure turbine results in a cheaper incremental cost for the dry tower cooling system. The difference in cost between the two turbines is dependent on the site weather conditions. For the Casper site the use of the high back pressure turbine results in a dry cooling system which is about \$600,000/year cheaper than the modified conventional turbine. For the Phoenix site the difference in cost is about \$3.3 million/year in favor of the high back pressure turbine. Table 6-5 shows that the modified conventional turbine uses much less fuel, i.e., the incremental fuel cost is much lower. However, this savings is nullified by the higher capital cost and higher energy and capacity penalties. The difference in dry tower cost for the 2 turbines for the same site is primarily a function of the fuel cost. Thus, the fuel cost, if different for sites compared, may significantly affect the conclusions drawn from the computed results.

Table 6-6 shows the total cost of the dry tower systems for both alternate turbines as a function of fuel cost for the Casper site. As the fuel cost increases, fuel savings begin to play a more dominant role and the modified conventional turbine becomes cheaper than the high back pressure turbine. Notice that when the unit fuel cost is \$1.50/MMBTU, the trend is reversed, i.e., the high back pressure turbine is more expensive than the modified conventional turbine by about \$1.23 million/year. At a fuel cost of \$1.50/MMBTU, the capital cost and energy penalties are still higher for a modified conventional turbine but the incremental fuel cost is about \$4 million lower in cost than for the high back pressure turbine. The results in Tables 6-5 and 6-6 are shown graphically in Figure 6.1 which shows the effect of unit fuel cost on dry tower systems for the 2 turbines. Figure 6.1 shows that for the Casper site the break-even fuel cost is slightly over \$1.00/MMBTU.

The high back pressure turbines seem quite attractive for hot climates and sites with low fuel costs. The capital cost of the high back pressure turbine here was assumed to be the same as the cost of a conventional turbine. However, the cost of the design modification for the operation of the turbine at high back end temperatures may outweigh the advantages of smaller energy penalties.

6.4 Effect of Condenser Type

Both surface condensers and direct contact condensers were studied for the Casper site with either a modified conventional turbine or a high back pressure turbine. Table 6-7 indicates that the use of a surface condenser would cost approximately \$200,000/year above the cost of a jet condenser. Basically, this is due to the fact that a surface condenser has about a 3^{o}F higher TTD than a direct contact condenser and requires an equivalently lower ITD tower design. Thus, the capital costs are higher for a system with a surface condenser. If a modified conventional turbine is used, this difference in the TTD will also result in higher penalties for the design with the surface condenser. This is not necessarily so for a high back pressure turbine, since its heat rate curve is much flatter, and a 3^{o}F rise in saturation tempera-

SITE = CASPER
CONDENSER TYPE = SURFACE
TURBINE TYPE = ---
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = ---
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20

TUBE CONFIGURATION = 6R2P
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
TUBE LENGTH (FT) = 80
HOURS ABOVE 82°F AMBIENT = 440

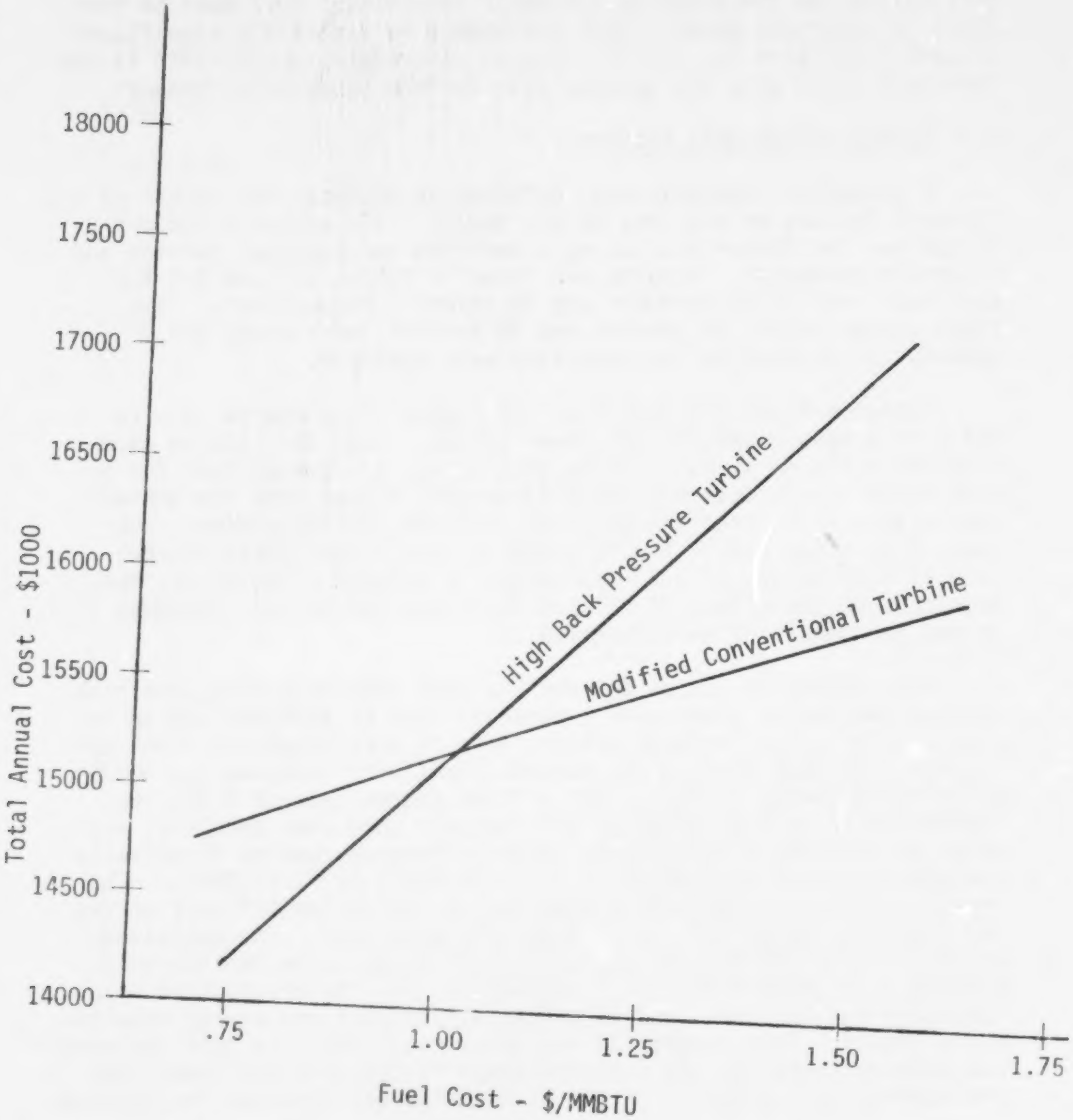


Figure 6.1. Total Annual Cost for Various Fuel Cost and Turbine Type - Casper.

ture is not quite as significant.

Another noteworthy observation about Table 6-7 is that the incremental fuel cost is lower for the system with a surface condenser. This results from the higher pumping power required for a direct contact system (on the order of 2.5 MWe). Additional fuel must be consumed to power the pumps. This difference is especially significant at part loads when fan control occurs. Therefore, an increase in the fuel cost could make the systems with surface condensers cheaper.

6.5 Effect of Economic Factors

A parametric analysis was performed to evaluate the effect of economic factors on the cost of dry towers. The analysis was performed for the Casper site using a modified conventional turbine and a surface condenser. Results are shown in Tables 6-8 and 6-9 for unit fuel cost of \$0.75/MMBTU and \$1.50/MMBTU respectively. Two fixed charge rates, 15 percent and 20 percent, were used, and 2 methods of accounting for penalties were employed.

Tables 6-8 and 6-9 show that the higher fixed charge rate results in a more expensive dry tower system. When the loss in capacity was replaced by gas turbine generation, the annual cost for a 0.20 fixed charge rate was about 20 percent higher than the annual cost with a 0.15 fixed charge rate. However, if replacement power came from a new plant, the increase in cost from a fixed charge rate of 0.15 to one of 0.20 was nearly 30 percent. Therefore, the magnitude of the effect of raising the fixed charge rate depended on how the penalties were assessed.

The results in Tables 6-8 and 6-9 show that assessing penalties using a new fossil plant with a capacity cost of \$500/KWe and an energy cost of 10 mills/KW-HR results in much more expensive plant operation than when using a gas turbine plant with \$100/KWe and 40/20 mills/KW-HR energy charges. For a fixed charge rate of 0.20, the difference in cost is about \$5 million/year more when penalties require an expanded fossil plant. This difference remains essentially unchanged whether the fuel cost is \$0.75/MMBTU or \$1.50/MMBTU. The reason for this difference is that the increased capital cost of the new plant far outweighs its savings in energy cost. The optimized dry cooling system for the expanded plant tends to be considerably bigger; i.e., more modules are needed than for the dry cooling system using gas turbines, and higher auxiliary cost and energy requirements result. This results in one beneficial effect in that the maximum back pressure for the expanded plant is considerably lower than the maximum back pressure of the plant using gas turbines for peaking.

6.6 Effect of Tube Configuration

The effect of the number of rows and passes of the dry cooling tower tube modules on the total annual cost is surprisingly small.

A careful look at the results in Tables 6-10, 6-11, and 6-12 shows the importance of optimizing the tower design for each set of conditions.

The first situation studied was for the Casper site with replacement power coming from gas turbines. The tube configurations used were: 6-row, 2-pass; 5-row, 2-pass; 4-row, 2-pass; and 4-row, 1-pass. These results are shown in Table 6-10. The difference in total annual cost for all the designs was under $200,000, which is slightly over a 1 percent change. In fact, the 2 cheaper designs, 6R2P and 4R2P, are only $5,000 apart. This occurs because the optimization procedure searches for the combination of design variables for the lowest cost. The 6-row, 2-pass design requires a lower number of modules with fewer piping components and smaller ground plot area than do the other configurations studied.

Table 6-11 shows the summary of the tube module configuration analysis for the Phoenix site using an expanded plant for replacement power ($500/KWe, 10/10 mills/KW-HR). The table shows almost identical cost for all 2-pass configurations. However, the 6-row, 2-pass tower requires 92 modules as compared with 124 modules for the 4-row, 2-pass design. The 4-row, 1-pass configuration is about $350,000 more expensive than the 2-pass arrangements.

Table 6-12 shows the effect of the penalty charges on the cost with different tube configurations. For the Casper site with an expanded plant for replacing lost capacity, the 4-row, 2-pass design is about $200,000 cheaper. However, for the Phoenix site with gas turbines used for replacing lost power, the 4-row, 2-pass design is about $350,000 more expensive.

Conclusions similar to those for the effect of tube configuration on cost follow from consideration of other design variables, such as fuel cost, fixed charge rate, etc. A different fuel cost, for example, could produce different results.

It seems that the savings in pumping costs for 1-pass designs is outweighed by the increased piping costs and reduced heat transfer capabilities. For the 2-pass designs, the number of rows is not a major consideration. Designs with 6 rows are probably more desirable since they require less plot area and fewer fans and modules. Above 6 rows, standard-size fans do not provide the necessary air flow, and schemes involving large diameter fans or sharing fans between bays would have to be employed.

6.7 Effect of Tube Length

The effect of tube length was studied by choosing three different situations and optimizing the design using 40-, 50-, 70-, and 80-ft. tubes. The general trend was a decrease in total annual cost with an increase in tube length. Tube lengths above 80 ft. were not studied because of uncertainties in shipping procedures. In all 3 cases, the 70-ft. design was slightly more expensive than the 60-ft. design. This was due to the fact that shipping costs are higher for lengths greater than 60 ft., and for tube lengths over 60 ft. a single fan per bay can no longer provide the required air flow. Thus, 2 fans per bay are required which increases the module cost and auxiliary power. Eighty-ft. tubes provide the economy of size over smaller designs and permit use of more efficient, larger fans in the design optimization.

Tables 6-13, 6-14 and 6-15 demonstrate these effects. For the Casper site with a modified conventional turbine and replacement capacity and energy coming from a gas turbine, there is a $1.1 million annual advantage of the 80- over the 40-ft. tubes. As the tube length increases, less modules are needed. This permits lower ITD designs using fewer modules with corresponding lower costs for piping, capacity, and energy penalties.

Table 6-15 shows the Phoenix site with a high back pressure turbine and penalties coming from a gas turbine. For this case the turbine heat rate curve is flatter, and the capacity and energy costs play a less significant role. The savings from 80-ft. to 40-ft. tubes ($1.1 million) are primarily due to the reduced module and piping costs that arise from fewer numbers of modules.

For Phoenix with a modified conventional turbine and penalties coming from a new plant, the cost difference is $1.3 million per year. As tube length increases, there are less modules and lower ITDs. This lowers the piping, capacity, and energy charges.

For the cases studied, it is evident that 80-ft. tubes are the most economical. The fact that they have an increased pressure drop is insignificant compared with the high costs of modules, and the amount of power required for the fans. Longer tubes should be studied to examine whether their increased handling and shipping costs are offset by their savings in other piping costs and whether their total cost is lower than that of shorter tubes.

6.8 Effect of Summer Hours

The "SUMMER HOURS NOT EXCEEDED" is a term used to determine how many of the hottest hours at a particular site can be ignored. Using the hottest temperature ever recorded to calculate capacity replacement, for instance, unfairly penalizes the dry cooling tower system. These high temperatures occur for short periods of time, and the power plant most probably will not see their effect due to the time constant of the plant. A commonly used rule is the 10-hour rule. In this rule, the hottest 10 hours of the year are ignored, and the highest temperature which is exceeded during those 10 hours is used for capacity replacement calculations and for energy penalties for the 10-hour duration. Another method is to use 1 percent of the 4 hottest months which corresponds to 29 hours. A third method used in this study had 2.5 percent of the 4 hottest months, which is 72 hours.

Table 6-16 shows the effect of going from the 10- to 29-hour rule for the Casper site with a modified conventional turbine. There was only a 1.4°F difference in the maximum ambient temperature, but for the case when penalties are made up by a new plant this can be significant. Since a new, expanded plant has relatively high capacity penalties, any reduction in turbine back pressure results in lower cost. Thus, the 29-hour case was $350,000 cheaper per year than the 10-hour case. The decrease in the highest ambient temperature allowed a decrease in back pressure and a large reduction in the capacity penalty. It required more modules and fans to do this, but the increased capital costs were compensated by the ability to use a lower capacity replacement. When the penalties come from a gas turbine, the effect is not as drastic since capacity replacement is relatively cheaper. The reduction in the highest ambient temperature simply allows a slight reduction in water flow rate and fan power. This increases the ITD and reduces the capital costs. The 29-hour case saved only $5,000 per year.

The same type of study was conducted for Phoenix with a modified conventional turbine; it is shown in Table 6-17. The difference in the maximum ambient temperature from 10 hours to 29 hours was 2.4°F. As in the Casper case, when penalties come from a new plant a savings occurs which is almost entirely due to the reduction in capacity penalty. For Phoenix this amounted to $650,000 annually. For penalties coming from a gas turbine the effect is much less drastic. The savings was only $40,000 annually. As in the Casper case, the fan power and water flow rate decreased allowing a higher ITD and lower capital costs. It was interesting to note that due to the large number of hours that the ambient is above 32°F at Phoenix, the energy penalty increased for the 29-hour case. This occurred because of the higher design ITD which offset some of the capital savings.

Table 6-18 shows the Phoenix site with a high back pressure turbine and with 10, 29, and 72 hours that are not exceeded. Penalties come from a gas turbine. The effect is small due to the flatness of the turbine heat rate curve and the fact that gas turbine capacity replacement is cheap. In going from 10 hours to 72 hours, there was a 4.1°F difference in maximum ambient temperature; yet, the savings was only $190,000 annually. As the number of summer hours not exceeded increases at a given site, the ITD also increases, thus reducing the total annual cost. For 29 hours this substantially lowered the capital costs and accrued large energy penalties during the many hours that the ambient was above 82°F. For 72 hours the optimum scheme decreased the capital costs less drastically and incurred slight increases in energy penalties.

The effect of the number of summer hours not exceeded, which a designer selects as a basis to calculate penalties, can be a significant factor in determining the total annual cost of a dry cooling tower. This cost depends on the type of turbine, penalty scheme, and climatic conditions.

6.9 Effect of ITD

The effect of ITD on an optimal design was studied by fixing the ITD at a specific value and finding the combination of other design variables which would produce the lowest cost for the specific ITD. Two sites were analyzed. The results for the Casper site with gas turbines are shown in Tables 6-19 and 6-20; the results for the Phoenix site with expanded plant for penalty assessments are shown in Tables 6-21 and 6-22. For both sites the total annual cost has a minimum point at a specific value of ITD. This is shown in Figures 6.2 and 6.3. Each point on these curves is an optimized point for that particular ITD. Any deviation of auxiliary power, range, etc., from those that are given in the tables could result in higher costs for that ITD.

The effect of ITD is obvious from looking at the tables. As the ITD increased the capital costs decreased, but the penalties increased. When the ITD increased, the number of modules and auxiliary power decreased while the maximum back pressure and loss in generation increased.

For the Phoenix case there was a \$2.8 million annual increase from the optimum design ITD of 40°F to an ITD of 60°F. It is noteworthy that a deviation of 5°F from the optimum design ITD gave a penalty of over \$300,000/year.

For the Casper case the optimum ITD was approximately 53°F. The corresponding cost was nearly \$4.2 million cheaper than for a design ITD of 30°F, and a 5°F deviation from the optimum cost less than \$200,000/year. Notice that the Casper curve is flatter near the optimum than the Phoenix curve. Casper was less sensitive because of its lower capacity replacement charge.

The choice for the design ITD can have a large effect on the annual cost. In addition, its optimum value is dependent on the site-related variables, penalty scheme, and economic parameters. These will also determine the shape of the ITD curve.

6.10 Effect of Range

The study of the effect of range was similar to the study of ITD, and range was shown to be a significant factor. The results are presented in Figures 6.4 and 6.5. Again, it must be remembered that each point is optimized for the conditions stated.

SITE = PHOENIX
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10

TUBE CONFIGURATION = 6R2P
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
TUBE LENGTH (FT) = 80
HOURS ABOVE 82°F AMBIENT = 2760
COST BASE = JAN. 1976

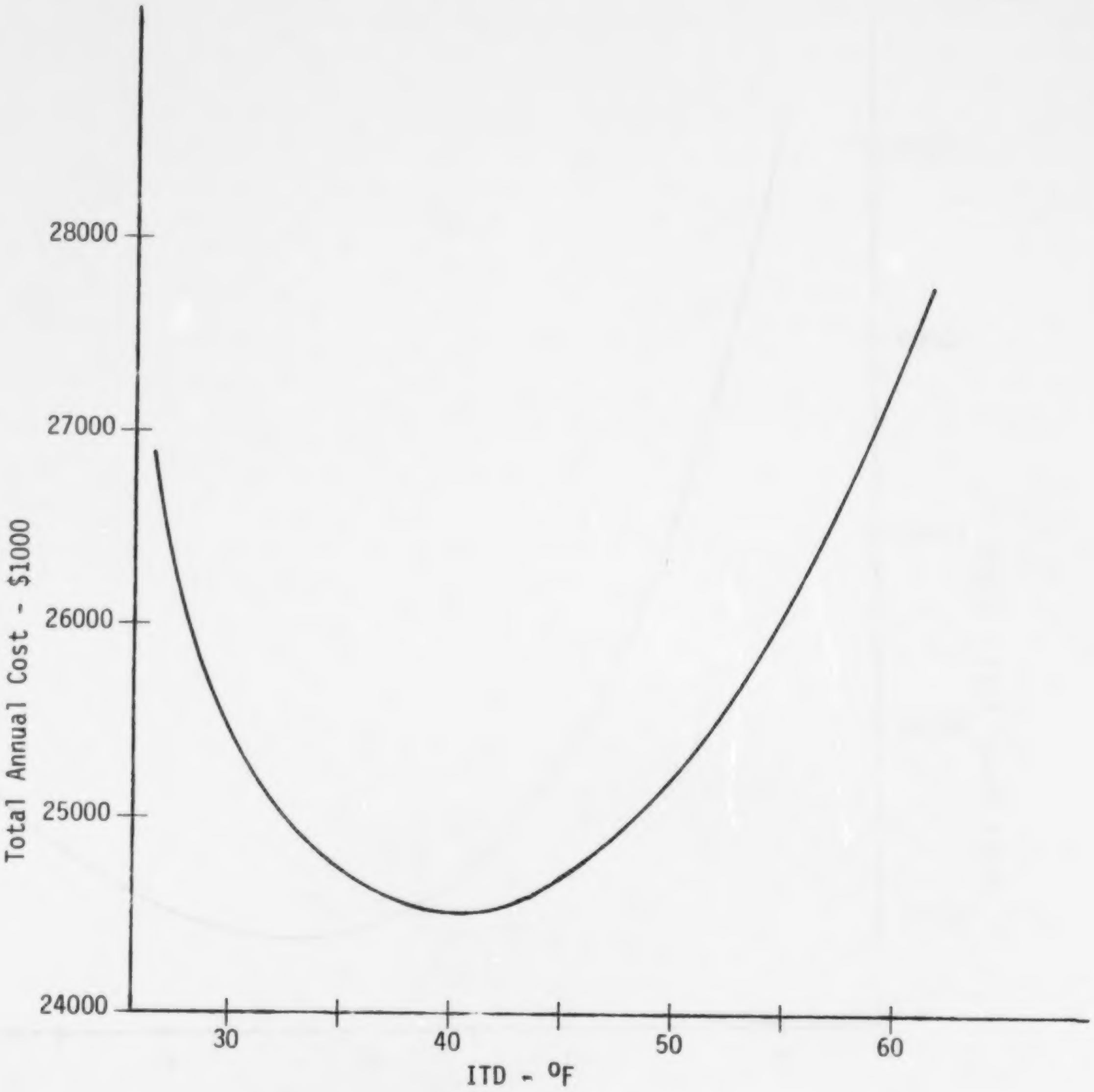


Figure 6.2. Total Annual Cost for Various ITDs - Phoenix.

SITE = CASPER
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20

TUBE CONFIGURATION = 6R2P
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
TUBE LENGTH (FT) = 80
HOURS ABOVE 82°F AMBIENT = 440
COST BASE = JAN. 1976

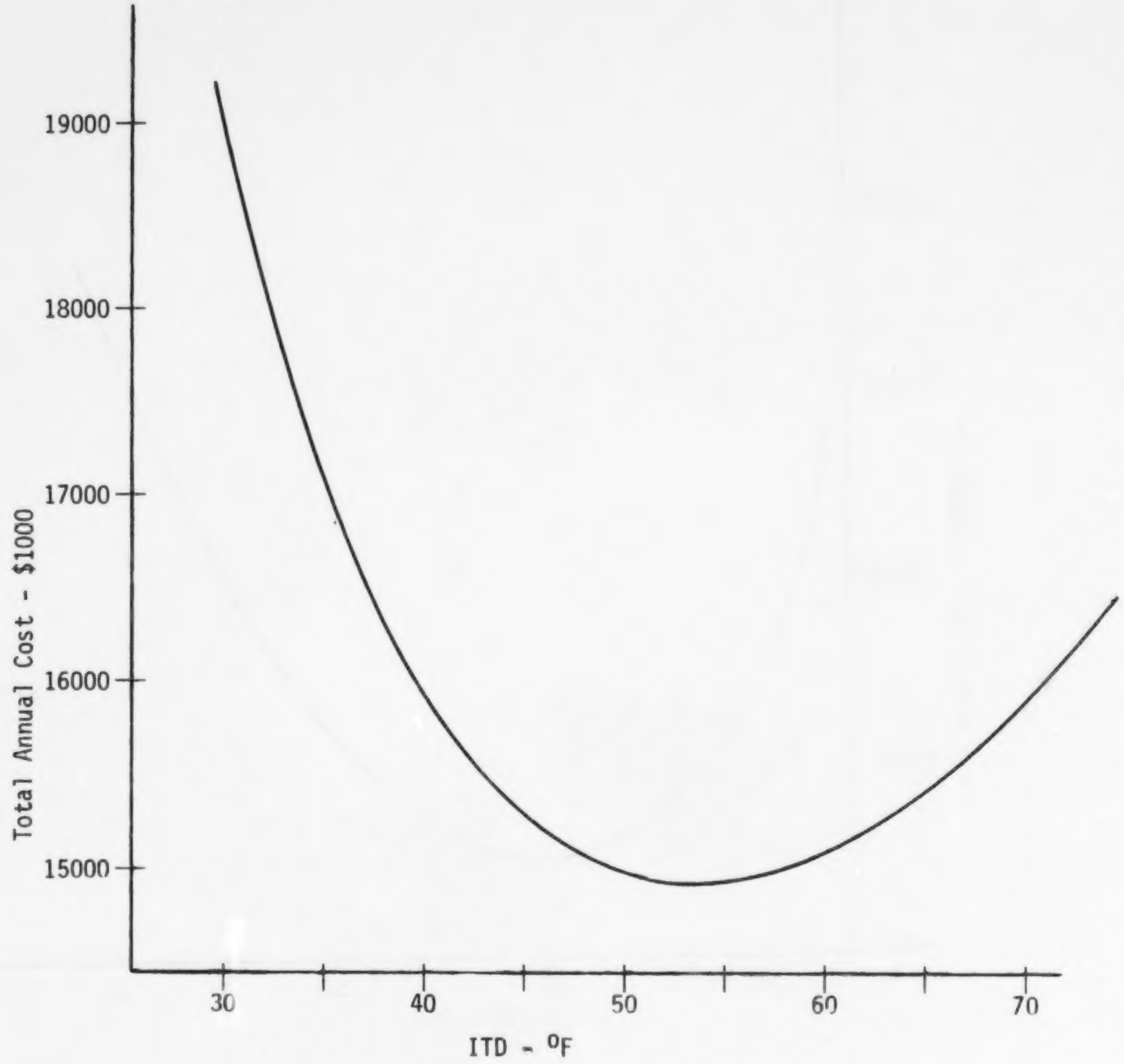


Figure 6.3. Total Annual Cost for Various ITDs - Casper.

SITE = PHOENIX
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10

TUBE CONFIGURATION = 6R2P
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
TUBE LENGTH (FT) = 80
HOURS ABOVE 82°F AMBIENT = 2760
COST BASE = JAN. 1976

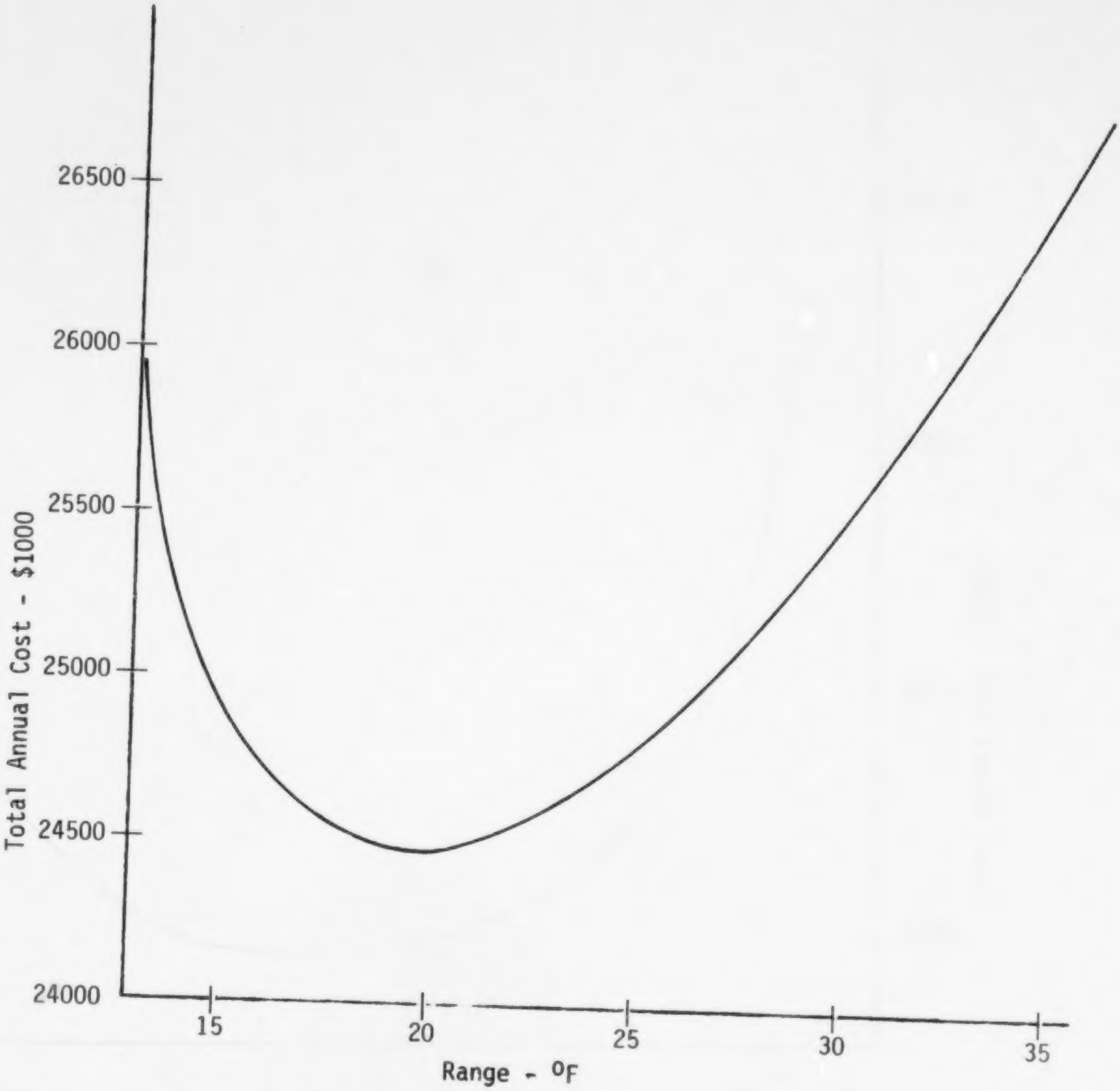


Figure 6.4. Total Annual Cost for Various Ranges - Phoenix.

SITE = CASPER
CONDENSER TYPE = SURFACE
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20

TUBE CONFIGURATION = 6R2P
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
TUBE LENGTH (FT) = 80
HOURS ABOVE 82°F AMBIENT = 440
COST BASE = JAN. 1976

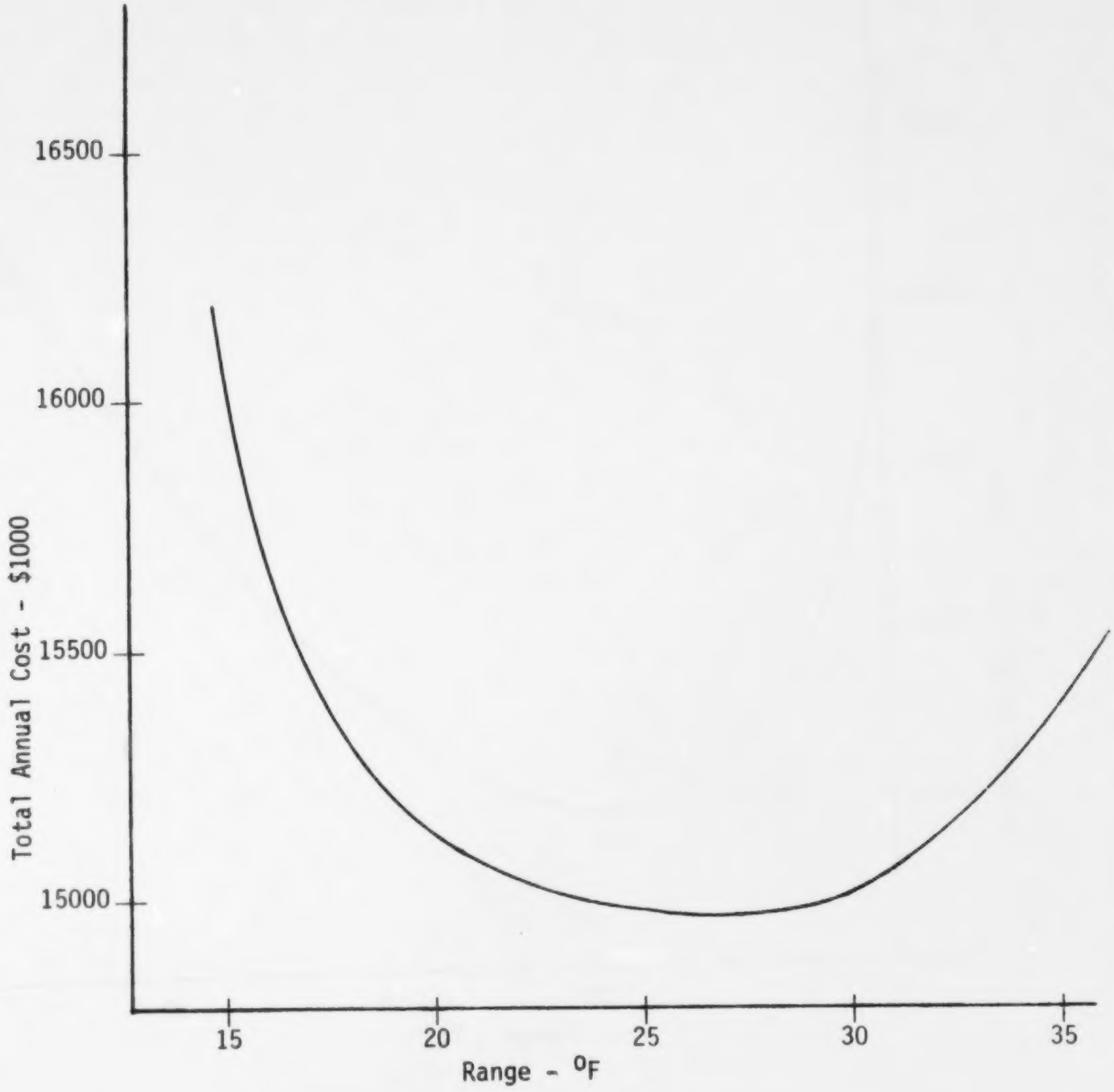


Figure 6.5. Total Annual Cost for Various Ranges - Casper.

The Phoenix case with a modified conventional turbine and penalties coming from a new plant can be found in Table 6-23. It is interesting to note that changing the range did not alter the number of modules. Changing the range did affect the water flow rate, however. As the range increased, the water flow rate dropped and resulted in smaller piping and condenser costs and larger ITDs. The larger ITD caused higher capacity and energy penalties since back pressure and loss in generation increased.

The trend of increasing penalties with decreasing capital costs resulted in a minimum total annual cost at a range of 20°F. At this point the total cost was $2 million less than that for an optimum design for a range of 35°F.

The Casper site with a modified conventional turbine and penalties coming from a gas turbine exhibited the same trend as the Phoenix case. The results are presented in Table 6-24. For Casper the range curve was much flatter and had a minimum annual cost at a range near 26°F. This represented a cost that was almost $1.2 million/year lower than for a tower designed for a range of 15°F.

TABLE 6-4. EFFECT OF SITE ON TOTAL ANNUAL COST

SITE = ----
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82^{O}F AMBIENT = ----
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	20522	15612	14869	14593	12817
SITE	PHOENIX	ATLANTA	CASPER	BISMARCK	BURLINGTON
HOURS ABOVE 82^{O}F AMBIENT	2760	783	440	415	176
AMBIENT EXCEEDED BY 29 HOURS (^{O}F)	109.5	95.3	93.1	96.1	88.2
MODULE COST ($1000)	5594	5370	4961	4846	4268
PIPING COST ($1000)	1964	1778	1661	1652	1420
CONDENSER COST ($1000)	990	854	828	844	730
CAPACITY PENALTY ($1000)	2293	1644	1828	1872	1798
ENERGY PENALTY ($1000)	6612	3184	3014	2815	2181
INCREMENTAL FUEL COST ($1000)	1316	1106	968	959	944
ANNUAL FUEL COST ($1000)	45541	45331	45192	45184	45169
NUMBER OF MODULES	80	76	72	68	60
TOTAL FAN POWER (MWe)	21	18	18	21	17
TOTAL AUXILIARY POWER (MWe)	29.0	24.7	24.4	28.1	22.4
MAXIMUM BACK PRESSURE (in. Hg)	9.7	7.5	8.2	8.1	8.2
MAXIMUM LOSS IN GENERATION (MWe)	114.7	82.2	91.4	93.6	89.9
TTD (^{O}F)	5.1	5.0	5.0	5.0	5.2
ITD (^{O}F)	43.9	48.4	53.9	50.6	58.8
RANGE (^{O}F)	21	24	26	25	31

TABLE 6-5. EFFECT OF TURBINE TYPE - CASPER AND PHOENIX

SITE = ----
TURBINE TYPE = ----
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = --
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	14255	14869	17193	20522
TURBINE TYPE	HIGH B.P.	MOD.CONV.	HIGH B.P.	MOD.CONV.
SITE	CASPER	CASPER	PHOENIX	PHOENIX
MODULE COST ($1000)	4645	4961	4660	5594
PIPING COST ($1000)	1465	1661	1684	1964
CONDENSER COST ($1000)	717	828	875	990
CAPACITY PENALTY ($1000)	833	1828	1268	2293
ENERGY PENALTY ($1000)	1059	3014	2930	6612
INCREMENTAL FUEL COST ($1000)	2963	968	3146	1316
ANNUAL FUEL COST ($1000)	47188	45192	47371	45541
NUMBER OF MODULES	68	72	68	80
TOTAL FAN POWER (MWe)	18	18	19	21
TOTAL AUXILIARY POWER (MWe)	23.1	24.4	27.1	29.0
MAXIMUM BACK PRESSURE (in. Hg)	10.4	8.2	12.4	9.7
MAXIMUM LOSS IN GENERATION (MWe)	41.7	91.4	63.4	114.7
TTD (°F)	5.7	5.0	5.1	5.1
ITD (°F)	64.3	53.9	55.9	43.9
RANGE (°F)	33	26	25	21
HOURS ABOVE 82°F AMBIENT	440	440	2760	2760

TABLE 6-6. EFFECT OF TURBINE TYPE - CASPER

SITE = CASPER
TURBINE TYPE = ----
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = ----
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82^{o}F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	17165	15936	15198	15236
TURBINE TYPE	HIGH B.P.	MOD.CONV.	HIGH B.P.	MOD.CONV.
FUEL COST ($/MMBTU)	1.50	1.50	1.00	1.00
MODULE COST ($1000)	4611	4812	4359	5026
PIPING COST ($1000)	1462	1620	1454	1739
CONDENSER COST ($1000)	730	815	722	879
CAPACITY PENALTY ($1000)	858	1918	977	1759
ENERGY PENALTY ($1000)	1013	3194	1192	2871
INCREMENTAL FUEL COST ($1000)	5931	1950	3965	1328
ANNUAL FUEL COST ($1000)	94381	90400	62932	60294
NUMBER OF MODULES	68	68	64	72
TOTAL FAN POWER (MWe)	14	17	15	18
TOTAL AUXILIARY POWER (MWe)	19.9	23.6	20.7	25.3
MAXIMUM BACK PRESSURE (in. Hg)	10.9	8.6	11.5	7.9
MAXIMUM LOSS IN GENERATION (MWe)	42.9	95.9	48.8	88.0
TTD (^{o}F)	5.2	5.2	5.3	5.1
ITD (^{o}F)	66.6	55.5	68.9	52.2
RANGE (^{o}F)	33	26	34	23

TABLE 6-7. EFFECT OF CONDENSER TYPE - CASPER

SITE = CASPER
TURBINE TYPE = ----
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = ----
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	14869	14600	14255	14072
CONDENSER TYPE	SURFACE	JET	SURFACE	JET
TURBINE TYPE	MOD.CONV.	MOD.CONV.	HIGH B.P.	HIGH B.P.
MODULE COST ($1000)	4961	4896	4645	4302
PIPING COST ($1000)	1661	1675	1465	1450
CONDENSER COST ($1000)	828	721	717	738
CAPACITY PENALTY ($1000)	1828	1751	833	834
ENERGY PENALTY ($1000)	3014	2856	1059	1109
INCREMENTAL FUEL COST ($1000)	968	1051	2963	3056
ANNUAL FUEL COST ($1000)	45192	45276	47188	47281
NUMBER OF MODULES	72	72	68	64
TOTAL FAN POWER (MWe)	18	17	18	17
TOTAL AUXILIARY POWER (MWe)	24.4	26.3	23.1	24.0
MAXIMUM BACK PRESSURE (in. Hg)	8.2	7.7	10.4	10.3
MAXIMUM LOSS IN GENERATION (MWe)	91.4	87.6	41.7	41.7
TTD (°F)	5.0	2.0	5.7	2.0
ITD (°F)	53.9	57.3	64.3	67.1
RANGE (°F)	26	27	33	32

TABLE 6-8. EFFECT OF FIXED CHARGE RATE, CAPACITY PENALTY, AND ENERGY PENALTY FOR FUEL COST OF $.75/MMBTU

SITE = CASPER
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = ----
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	19661	15264	14869	12253
FIXED CHARGE RATE	.20	.15	.20	.15
CAPACITY COST ($/KWe)	500	500	100	100
ENERGY COST (MILLS/KW-HR)	10/10	10/10	40/20	40/20
MODULE COST ($1000)	6294	4518	4961	3962
PIPING COST ($1000)	2168	1485	1661	1329
CONDENSER COST ($1000)	1028	702	828	674
CAPACITY PENALTY ($1000)	6613	5458	1828	1262
ENERGY PENALTY ($1000)	680	727	3014	2726
INCREMENTAL FUEL COST ($1000)	1005	949	968	967
ANNUAL FUEL COST ($1000)	45230	45174	45192	45192
NUMBER OF MODULES	92	88	72	76
TOTAL FAN POWER (MWe)	21	17	18	17
TOTAL AUXILIARY POWER (MWe)	29.2	24.3	24.4	23.9
MAXIMUM BACK PRESSURE (in. Hg)	6.0	6.8	8.2	7.7
MAXIMUM LOSS IN GENERATION (MWe)	66.1	72.8	91.4	84.2
TTD (°F)	5.2	5.1	5.0	5.1
ITD (°F)	42.4	47.0	53.9	51.7
RANGE (°F)	19	22	26	24

TABLE 6-9. EFFECT OF FIXED CHARGE RATE, CAPACITY PENALTY, AND ENERGY PENALTY FOR FUEL COST OF $1.50/MMBTU

SITE = CASPER
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = ----
FUEL COST ($/MMBTU) = 1.50
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	20526	16206	15936	13197
FIXED CHARGE RATE	.20	.15	.20	.15
CAPACITY COST ($/KWe)	500	500	100	100
ENERGY COST (MILLS/KW-HR)	10/10	10/10	40/20	40/20
MODULE COST ($1000)	6204	4388	4812	3924
PIPING COST ($1000)	2006	1475	1620	1246
CONDENSER COST ($1000)	976	747	815	637
CAPACITY PENALTY ($1000)	6956	5475	1918	1339
ENERGY PENALTY ($1000)	706	769	3194	2912
INCREMENTAL FUEL COST ($1000)	1865	1930	1950	1826
ANNUAL FUEL COST ($1000)	90314	90380	90400	90276
NUMBER OF MODULES	88	84	68	76
TOTAL FAN POWER (MWe)	21	21	17	18
TOTAL AUXILIARY POWER (MWe)	27.9	28.4	23.6	23.3
MAXIMUM BACK PRESSURE (in. Hg)	6.4	6.6	8.6	8.1
MAXIMUM LOSS IN GENERATION (MWe)	69.6	73.0	95.9	89.3
TTD (°F)	5.0	5.2	5.2	5.0
ITD (°F)	44.5	45.7	55.5	53.6
RANGE (°F)	23	21	26	27

TABLE 6-10. EFFECT OF TUBE CONFIGURATION - CASPER

SITE = CASPER
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = ----
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 10
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	14945	15136	14940	15054
TUBE CONFIGURATION	6R2P	5R2P	4R2P	4R1P
MODULE COST ($1000)	4979	4665	4776	4506
PIPING COST ($1000)	1702	1422	1528	1850
CONDENSER COST ($1000)	872	698	737	968
CAPACITY PENALTY ($1000)	1842	2229	2056	1964
ENERGY PENALTY ($1000)	2921	3674	3338	3184
INCREMENTAL FUEL COST ($1000)	996	928	941	976
ANNUAL FUEL COST ($1000)	45221	45153	45166	45201
NUMBER OF MODULES	72	76	88	80
TOTAL FAN POWER (MWe)	21	17	19	22
TOTAL AUXILIARY POWER (MWe)	28.1	22.3	25.3	28.6
MAXIMUM BACK PRESSURE (in. Hg)	8.0	9.9	9.0	8.4
MAXIMUM LOSS IN GENERATION (MWe)	92.1	111.5	102.8	98.2
TTD (°F)	5.0	5.1	5.2	5.4
ITD (°F)	51.5	60.0	56.0	52.9
RANGE (°F)	24	34	31	19

TABLE 6-11. EFFECT OF TUBE CONFIGURATION - PHOENIX

SITE = PHOENIX
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10
COST BASE = JAN. 1976

TUBE CONFIGURATION = ----
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 10
HOURS ABOVE 82°F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	25205	25167	25193	25543
TUBE CONFIGURATION	6R2P	5R2P	4R2P	4R1P
MODULE COST ($1000)	6317	6372	6651	6295
PIPING COST ($1000)	2128	2096	2163	2405
CONDENSER COST ($1000)	996	914	936	1059
CAPACITY PENALTY ($1000)	11205	11252	10905	11180
ENERGY PENALTY ($1000)	1478	1479	1425	1482
INCREMENTAL FUEL COST ($1000)	1219	1202	1207	1214
ANNUAL FUEL COST ($1000)	45444	45426	45432	45439
NUMBER OF MODULES	92	104	124	116
TOTAL FAN POWER (MWe)	21	19	20	22
TOTAL AUXILIARY POWER (MWe)	28.7	27.2	29.1	29.5
MAXIMUM BACK PRESSURE (in. Hg)	9.5	9.6	9.2	9.4
MAXIMUM LOSS IN GENERATION (MWe)	112.1	112.5	109.0	111.8
TTD (°F)	5.0	5.1	5.0	5.1
ITD (°F)	40.9	41.7	40.0	40.9
RANGE (°F)	20	22	21	17

TABLE 6-12. EFFECT OF TUBE CONFIGURATION - COMPARISON AT CASPER AND PHOENIX

SITE = -----
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = -----
ENERGY COST (MILLS/KW-HR) = -----
COST BASE = JAN. 1976

TUBE CONFIGURATION = ----
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 10
HOURS ABOVE 82°F AMBIENT = -----
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED

SITE	CASPER	CASPER	PHOENIX	PHOENIX
TOTAL COST ($1000)	20016	19823	20564	20918
TUBE CONFIGURATION	6R2P	4R2P	6R2P	4R2P
CAPACITY COST ($/KWe)	500	500	100	100
ENERGY COST (MILLS/KW-HR)	10/10	10/10	40/20	40/20
MODULE COST ($1000)	6125	5879	5926	5728
PIPING COST ($1000)	2054	1890	2017	1982
CONDENSER COST ($1000)	923	852	960	879
CAPACITY PENALTY ($1000)	7375	7734	2334	2471
ENERGY PENALTY ($1000)	736	753	6257	6773
INCREMENTAL FUEL COST ($1000)	982	951	1270	1322
ANNUAL FUEL COST ($1000)	45207	45176	45495	45547
NUMBER OF MODULES	88	108	84	104
TOTAL FAN POWER (MWe)	20	20	21	21
TOTAL AUXILIARY POWER (MWe)	28.2	27.6	29.7	29.7
MAXIMUM BACK PRESSURE (in. Hg)	6.6	6.9	9.8	10.3
MAXIMUM LOSS IN GENERATION (MWe)	73.8	77.3	116.7	123.5
TTD (°F)	5.4	5.0	5.2	5.3
ITD (°F)	44.4	46.3	42.0	44.6
RANGE (°F)	21	25	20	23
HOURS ABOVE 82°F AMBIENT	440	440	2760	2760

TABLE 6-13. EFFECT OF TUBE LENGTH - CASPER

SITE = CASPER
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = ----
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	15991	15286	15452	14869
TUBE LENGTH (FT)	40	60	70	80
MODULE COST ($1000)	4988	4924	5200	4961
PIPING COST ($1000)	1823	1757	1668	1661
CONDENSER COST ($1000)	874	886	789	828
CAPACITY PENALTY ($1000)	2077	1920	1927	1828
ENERGY PENALTY ($1000)	3591	3203	3277	3014
INCREMENTAL FUEL COST ($1000)	990	971	955	968
ANNUAL FUEL COST ($1000)	45215	45196	45180	45192
NUMBER OF MODULES	124	92	80	72
TOTAL FAN POWER (MWe)	20	18	19	18
TOTAL AUXILIARY POWER (MWe)	25.8	24.2	25.2	24.4
MAXIMUM BACK PRESSURE (in. Hg)	9.0	8.5	8.5	8.2
MAXIMUM LOSS IN GENERATION (MWe)	103.9	96.0	96.3	91.4
TTD (°F)	5.0	5.0	5.1	5.0
ITD (°F)	57.5	55.6	58.0	53.9
RANGE (°F)	23	24	28	26

TABLE 6-14. EFFECT OF TUBE LENGTH - PHOENIX WITH MODIFIED CONVENTIONAL TURBINE

SITE = PHOENIX
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = ----
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	25869	25048	25097	24549
TUBE LENGTH (FT)	40	60	70	80
MODULE COST ($1000)	6433	6518	6200	6224
PIPING COST ($1000)	2468	2299	2200	2185
CONDENSER COST ($1000)	1058	1005	1032	1008
CAPACITY PENALTY ($1000)	11061	10607	10962	10526
ENERGY PENALTY ($1000)	1591	1488	1558	1480
INCREMENTAL FUEL COST ($1000)	1319	1222	1283	1264
ANNUAL FUEL COST ($1000)	45544	45447	45508	45489
NUMBER OF MODULES	164	120	96	88
TOTAL FAN POWER (MWe)	21	19	19	20
TOTAL AUXILIARY POWER (MWe)	29.9	27.1	28.5	29.2
MAXIMUM BACK PRESSURE (in. Hg)	9.3	9.1	9.3	8.9
MAXIMUM LOSS IN GENERATION (MWe)	110.6	106.1	109.6	105.3
TTD (°F)	5.2	5.1	5.0	5.1
ITD (°F)	42.6	41.8	42.5	40.7
RANGE (°F)	17	19	18	19

TABLE 6-15. EFFECT OF TUBE LENGTH - PHOENIX WITH HIGH BACK PRESSURE TURBINE

SITE = PHOENIX
TURBINE TYPE = HIGH B.P.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = ----
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82^oF AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	18280	17601	17614	17193
TUBE LENGTH (FT)	40	60	70	80
MODULE COST ($1000)	5575	5028	5180	4660
PIPING COST ($1000)	2032	1938	1746	1684
CONDENSER COST ($1000)	861	988	871	875
CAPACITY PENALTY ($1000)	1248	1213	1274	1268
ENERGY PENALTY ($1000)	2717	2614	2794	2930
INCREMENTAL FUEL COST ($1000)	3066	3107	3062	3146
ANNUAL FUEL COST ($1000)	47291	47332	47287	47371
NUMBER OF MODULES	140	92	80	68
TOTAL FAN POWER (MWe)	17	17	16	19
TOTAL AUXILIARY POWER (MWe)	23.6	23.8	21.9	27.1
MAXIMUM BACK PRESSURE (in. Hg)	12.7	12.5	13.1	12.4
MAXIMUM LOSS IN GENERATION (MWe)	62.4	60.7	63.7	63.4
TTD (^oF)	5.2	5.2	5.0	5.1
ITD (^oF)	56.6	55.6	58.1	55.9
RANGE (^oF)	26	22	27	25

TABLE 6-16. EFFECT OF CHANGING NUMBER OF SUMMER HOURS NOT EXCEEDED - CASPER

SITE = CASPER
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = ----
ENERGY COST (MILLS/KW-HR) = ----
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = ----
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	20016	19661	14945	14869
SUMMER HOURS NOT EXCEEDED	10	29	10	29
CAPACITY COST ($/KWe)	500	500	100	100
ENERGY COST (MILLS/KW-HR)	10/10	10/10	40/20	40/20
MODULE COST ($1000)	6125	6294	4979	4961
PIPING COST ($1000)	2054	2168	1702	1661
CONDENSER COST ($1000)	923	1028	872	828
CAPACITY PENALTY ($1000)	7375	6613	1842	1828
ENERGY PENALTY ($1000)	736	680	2921	3014
INCREMENTAL FUEL COST ($1000)	982	1005	996	968
ANNUAL FUEL COST ($1000)	45207	45230	45221	45192
NUMBER OF MODULES	88	92	72	72
TOTAL FAN POWER (MWe)	20	21	21	18
TOTAL AUXILIARY POWER (MWe)	28.2	29.2	28.1	24.4
MAXIMUM BACK PRESSURE (in. Hg)	6.6	6.0	8.0	8.2
MAXIMUM LOSS IN GENERATION (MWe)	73.8	66.1	92.1	91.4
TTD (°F)	5.4	5.2	5.0	5.0
ITD (°F)	44.4	42.4	51.5	53.9
RANGE (°F)	21	19	24	26
HIGHEST AMBIENT TEMPERATURE (°F)	94.5	93.1	94.5	93.1

TABLE 6-17. EFFECT OF CHANGING NUMBER OF SUMMER HOURS NOT EXCEEDED - PHOENIX WITH MODIFIED CONVENTIONAL TURBINE

SITE = PHOENIX
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = ----
ENERGY COST (MILLS/KW-HR) = ----
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = ----
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	25205	24549	20564	20522
SUMMER HOURS NOT EXCEEDED	10	29	10	29
CAPACITY COST ($/KWe)	500	500	100	100
ENERGY COST (MILLS/KW-HR)	10/10	10/10	40/20	40/20
MODULE COST ($1000)	6317	6224	5926	5594
PIPING COST ($1000)	2128	2185	2017	1964
CONDENSER COST ($1000)	996	1008	960	990
CAPACITY PENALTY ($1000)	11205	10526	2334	2293
ENERGY PENALTY ($1000)	1478	1480	6257	6612
INCREMENTAL FUEL COST ($1000)	1219	1264	1270	1316
ANNUAL FUEL COST ($1000)	45444	45489	45495	45541
NUMBER OF MODULES	92	88	84	80
TOTAL FAN POWER (MWe)	21	20	21	21
TOTAL AUXILIARY POWER (MWe)	28.7	29.2	29.7	29.0
MAXIMUM BACK PRESSURE (in. Hg)	9.5	8.9	9.8	9.7
MAXIMUM LOSS IN GENERATION (MWe)	112.1	105.3	116.7	114.7
TTD (°F)	5.0	5.1	5.2	5.1
ITD (°F)	40.9	40.7	42.0	43.9
RANGE (°F)	20	19	20	21
HIGHEST AMBIENT TEMPERATURE (°F)	111.9	109.5	111.9	109.5

TABLE 6-18. EFFECT OF CHANGING NUMBER OF SUMMER HOURS NOT EXCEEDED - PHOENIX WITH HIGH BACK PRESSURE TURBINE

SITE = PHOENIX
TURBINE TYPE = HIGH B.P.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = --
HOURS ABOVE 82°F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	17260	17193	17069
SUMMER HOURS NOT EXCEEDED	10	29	72
HIGHEST AMBIENT TEMPERATURE (°F)	111.9	109.5	107.8
MODULE COST ($1000)	5301	4660	5026
PIPING COST ($1000)	1792	1684	1707
CONDENSER COST ($1000)	858	875	822
CAPACITY PENALTY ($1000)	1174	1268	1131
ENERGY PENALTY ($1000)	2340	2930	2636
INCREMENTAL FUEL COST ($1000)	3075	3146	3084
ANNUAL FUEL COST ($1000)	47300	47371	47309
NUMBER OF MODULES	76	68	72
TOTAL FAN POWER (MWe)	19	19	17
TOTAL AUXILIARY POWER (MWe)	26.1	27.1	23.6
MAXIMUM BACK PRESSURE (in. Hg)	12.0	12.4	12.0
MAXIMUM LOSS IN GENERATION (MWe)	58.7	63.4	56.5
TTD (°F)	5.0	5.1	5.2
ITD (°F)	52.5	55.9	56.6
RANGE (°F)	26	25	28

TABLE 6-19. EFFECT OF ITDs OF 30-45^{o}F - CASPER

SITE = CASPER
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82^{o}F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	19030	17225	16040	15264
ITD (^{o}F)	30	35	40	45
MODULE COST ($1000)	9008	7426	6423	5775
PIPING COST ($1000)	2864	2481	2223	1963
CONDENSER COST ($1000)	1087	1054	1018	944
CAPACITY PENALTY ($1000)	1123	1202	1318	1472
ENERGY PENALTY ($1000)	1581	1953	2109	2336
INCREMENTAL FUEL COST ($1000)	1033	1030	1041	998
ANNUAL FUEL COST ($1000)	45258	45254	45266	45223
NUMBER OF MODULES	128	108	92	84
TOTAL FAN POWER (MWe)	36	31	25	22
TOTAL AUXILIARY POWER (MWe)	45.9	41.0	34.8	30.2
MAXIMUM BACK PRESSURE (in. Hg)	4.3	4.9	5.7	6.5
MAXIMUM LOSS IN GENERATION (MWe)	56.2	60.1	65.9	73.6
TTD (^{o}F)	5.5	5.2	5.3	5.1
RANGE (^{o}F)	16	17	18	21

TABLE 6-20. EFFECT OF ITDs OF 50-70°F - CASPER

SITE = CASPER
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	14955	15173	15907
ITD (°F)	50	60	70
MODULE COST ($1000)	5252	4491	4106
PIPING COST ($1000)	1766	1555	1398
CONDENSER COST ($1000)	865	782	714
CAPACITY PENALTY ($1000)	1686	2127	2552
ENERGY PENALTY ($1000)	2737	3689	4661
INCREMENTAL FUEL COST ($1000)	979	997	1027
ANNUAL FUEL COST ($1000)	45204	45221	45252
NUMBER OF MODULES	76	64	60
TOTAL FAN POWER (MWe)	20	18	16
TOTAL AUXILIARY POWER (MWe)	27.4	24.5	21.5
MAXIMUM BACK PRESSURE (in. Hg)	7.4	9.3	11.3
MAXIMUM LOSS IN GENERATION (MWe)	84.3	106.4	127.6
TTD (°F)	5.2	5.1	5.2
RANGE (°F)	24	28	34

TABLE 6-21. EFFECT OF ITDs OF 30-40°F - PHOENIX

SITE = PHOENIX
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	25795	24807	24489
ITD (°F)	30	35	40
MODULE COST ($1000)	8830	7222	6564
PIPING COST ($1000)	2832	2515	2194
CONDENSER COST ($1000)	1169	1083	957
CAPACITY PENALTY ($1000)	8363	9387	10225
ENERGY PENALTY ($1000)	1165	1298	1435
INCREMENTAL FUEL COST ($1000)	1135	1256	1216
ANNUAL FUEL COST ($1000)	45360	45481	45441
NUMBER OF MODULES	128	104	96
TOTAL FAN POWER (MWe)	28	24	21
TOTAL AUXILIARY POWER (MWe)	38.1	34.1	29.3
MAXIMUM BACK PRESSURE (in. Hg)	6.6	7.6	8.6
MAXIMUM LOSS IN GENERATION (MWe)	83.6	93.9	102.3
TTD (°F)	5.0	5.1	5.0
RANGE (°F)	16	17	20

TABLE 6-22. EFFECT OF ITDs OF 45-60°F - PHOENIX

SITE = PHOENIX
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	24749	25291	27338
ITD (°F)	45	50	60
MODULE COST ($1000)	5926	5648	5073
PIPING COST ($1000)	1946	1851	1548
CONDENSER COST ($1000)	923	881	733
CAPACITY PENALTY ($1000)	11294	12132	14794
ENERGY PENALTY ($1000)	1624	1781	2238
INCREMENTAL FUEL COST ($1000)	1257	1276	1375
ANNUAL FUEL COST ($1000)	45482	45501	45600
NUMBER OF MODULES	84	80	72
TOTAL FAN POWER (MWe)	20	18	14
TOTAL AUXILIARY POWER (MWe)	26.8	24.9	19.4
MAXIMUM BACK PRESSURE (in. Hg)	9.7	10.5	13.4
MAXIMUM LOSS IN GENERATION (MWe)	112.9	121.3	147.9
TTD (°F)	5.0	5.0	5.0
RANGE (°F)	23	26	32

TABLE 6-23. EFFECT OF RANGE - PHOENIX

SITE = PHOENIX
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 500
ENERGY COST (MILLS/KW-HR) = 10/10
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 2760
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	24951	24491	24914	25437	26487
RANGE (°F)	15	20	25	30	35
MODULE COST ($1000)	6480	6317	6317	6378	6273
PIPING COST ($1000)	2597	2128	1939	1772	1696
CONDENSER COST ($1000)	1201	1001	828	745	707
CAPACITY PENALTY ($1000)	9929	10445	11135	11773	12905
ENERGY PENALTY ($1000)	1390	1487	1616	1733	1919
INCREMENTAL FUEL COST ($1000)	1329	1241	1257	1242	1238
ANNUAL FUEL COST ($1000)	45554	45466	45482	45467	45463
NUMBER OF MODULES	92	92	92	92	92
TOTAL FAN POWER (MWe)	21	24	23	23	18
TOTAL AUXILIARY POWER (MWe)	32.6	32.1	29.4	27.8	22.2
MAXIMUM BACK PRESSURE (in. Hg)	8.2	8.6	9.3	10.0	11.4
MAXIMUM LOSS IN GENERATION (MWe)	99.3	104.5	111.3	117.7	129.0
TTD (°F)	5.0	5.0	5.1	5.1	5.0
ITD (°F)	37.7	39.9	43.3	45.9	51.2

TABLE 6-24. EFFECT OF RANGE - CASPER

SITE = CASPER
TURBINE TYPE = MOD.CONV.
FIXED CHARGE RATE = .20
FUEL COST ($/MMBTU) = .75
CAPACITY COST ($/KWe) = 100
ENERGY COST (MILLS/KW-HR) = 40/20
COST BASE = JAN. 1976

TUBE CONFIGURATION = 6R2P
CONDENSER TYPE = SURFACE
TUBE LENGTH (FT) = 80
CAPACITY FACTOR = .75
SUMMER HOURS NOT EXCEEDED = 29
HOURS ABOVE 82°F AMBIENT = 440
TOTAL GENERATION (MW-HR) = 6,570,000

NOTE: ALL COSTS ARE ANNUALIZED.

TOTAL COST ($1000)	16089	15145	14934	14972	15370
RANGE (°F)	15	20	25	30	35
MODULE COST ($1000)	4986	5060	4914	5091	4961
PIPING COST ($1000)	2279	1895	1840	1547	1444
CONDENSER COST ($1000)	1146	962	834	746	673
CAPACITY PENALTY ($1000)	1718	1695	1840	1899	2140
ENERGY PENALTY ($1000)	2927	2794	3077	3167	3686
INCREMENTAL FUEL COST ($1000)	1281	1058	981	924	916
ANNUAL FUEL COST ($1000)	45506	45282	45206	45149	45140
NUMBER OF MODULES	72	72	72	72	72
TOTAL FAN POWER (MWe)	18	20	19	19	17
TOTAL AUXILIARY POWER (MWe)	33.4	29.7	26.3	24.0	21.1
MAXIMUM BACK PRESSURE (in. Hg)	7.1	7.3	8.1	8.5	9.7
MAXIMUM LOSS IN GENERATION (MWe)	85.9	84.8	92.0	95.0	107.0
TTD (°F)	5.1	5.1	5.1	5.0	5.1
ITD (°F)	48.5	49.4	53.5	55.5	60.3

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APPENDIX A

Curves showing the heat rate and heat rejected vs. back pressure for the turbines used in this study.

1000 MWe CONVENTIONAL TURBINE
(FOR STUDY PURPOSES ONLY)

Note: Turbine has net heat rate of 8047 BTU/KW-HR at 3.5 in. Hg absolute. Heat rates assume 10 percent stack losses.

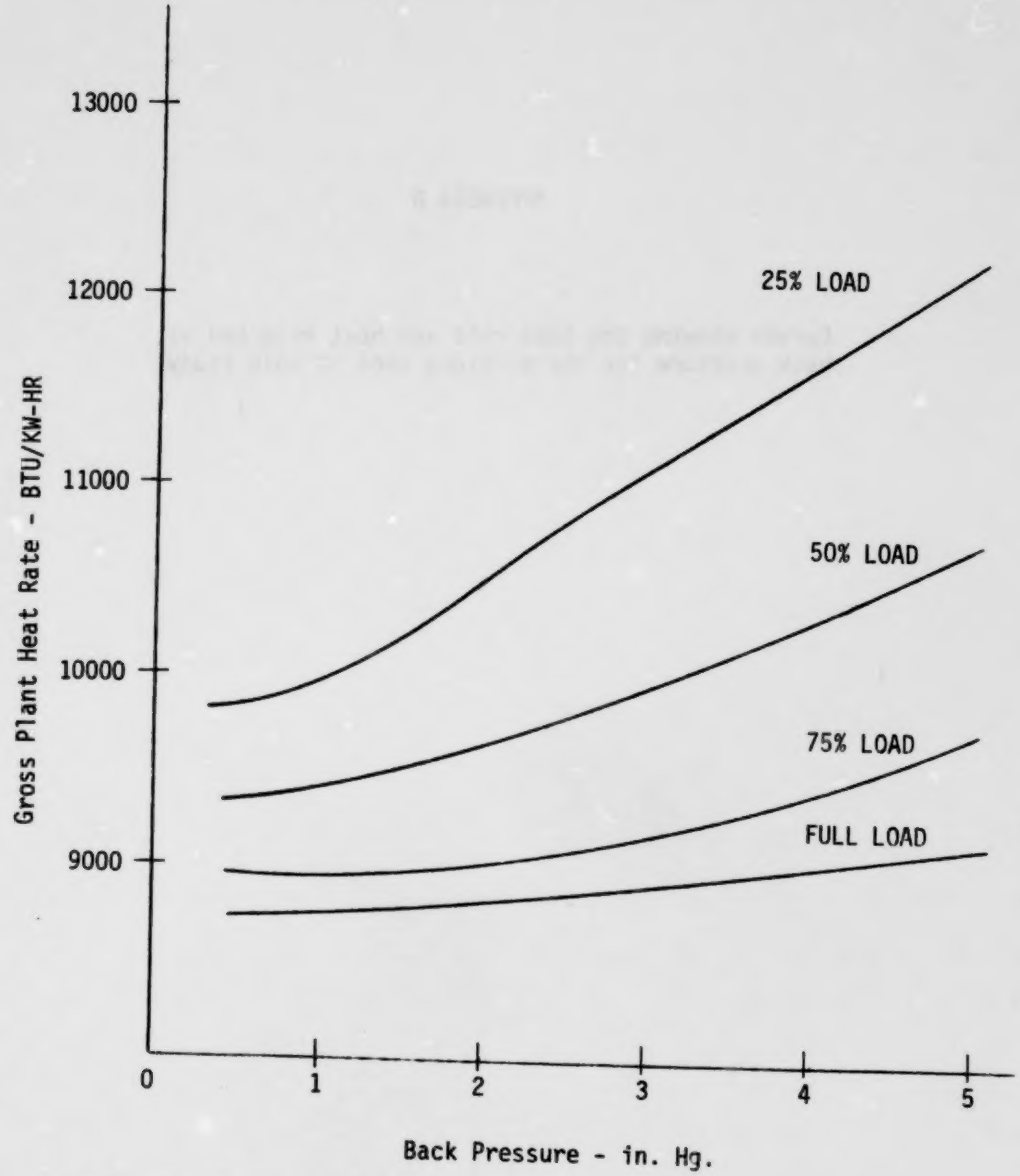

Figure A.1. Gross Plant Heat Rate with a Conventional Turbine in Fossil Fuel Units.

1000 MWe MODIFIED CONVENTIONAL TURBINE
(FOR STUDY PURPOSES ONLY)

Note: Heat Rates are calculated from ratios which are based on a conventional turbine at 3.5 in. Hg absolute with 8047 BTU/KW-HR net. Heat rates assume 10 percent stack losses.

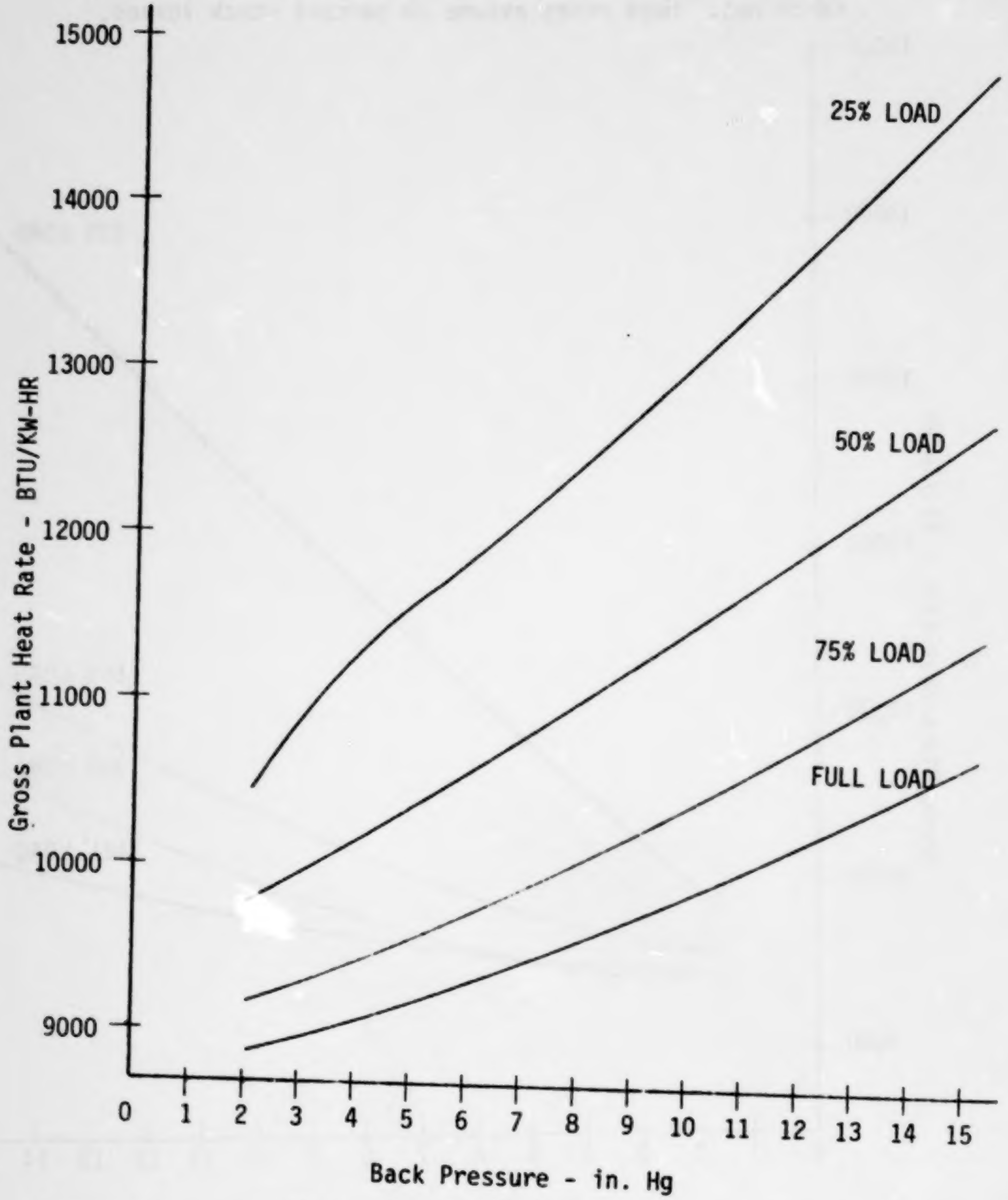

Figure A.2. Gross Plant Heat Rate with a Modified Conventional Turbine in Fossil Fuel Units

1000 MWe HIGH BACK PRESSURE TURBINE
(FOR STUDY PURPOSES ONLY)

Note: Heat Rates are calculated from ratios which are based on a conventional turbine at 3.5 in. Hg absolute with 8047 BTU/KW-HR net. Heat rates assume 10 percent stack losses.

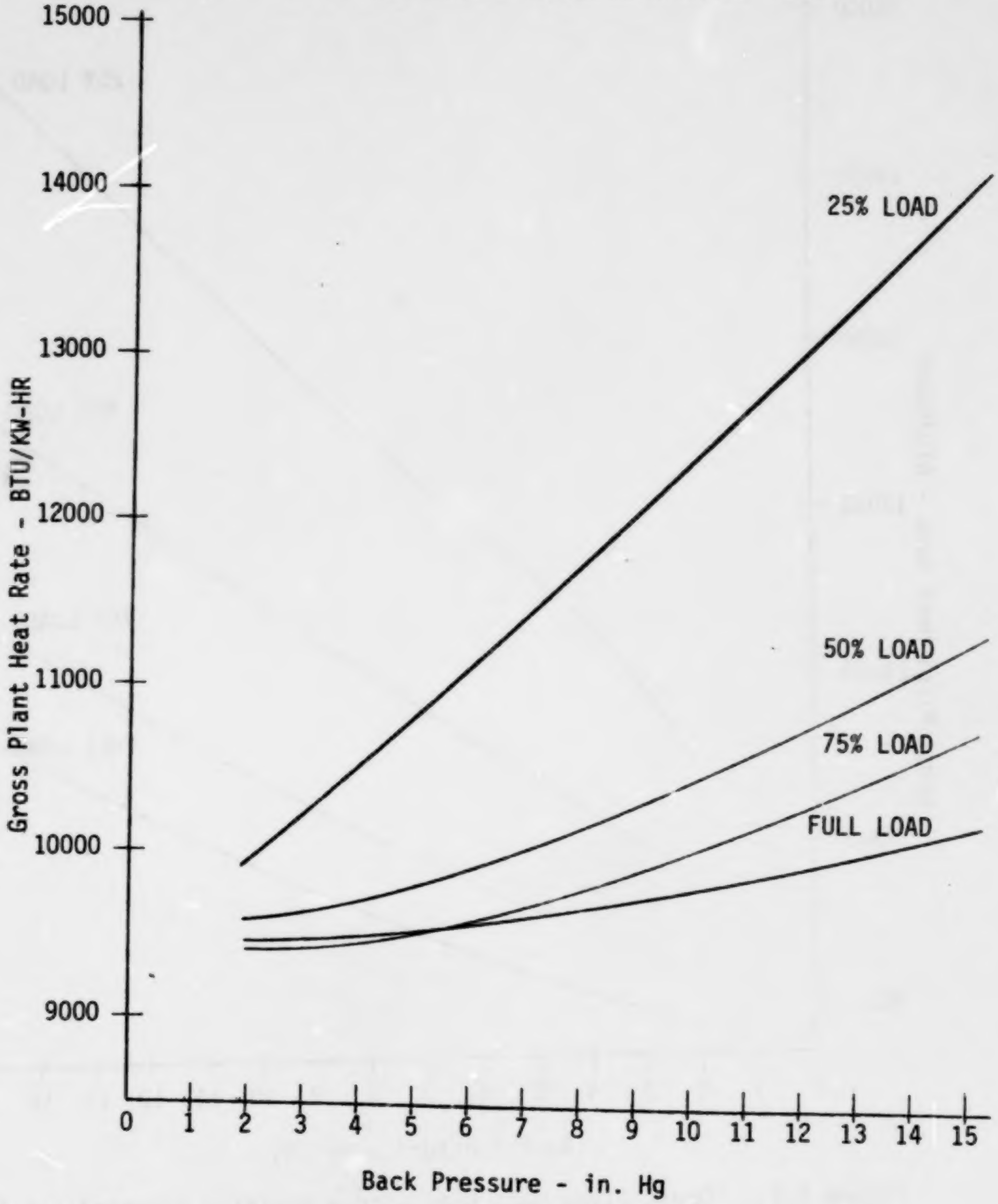

Figure A.3. Gross Plant Heat Rate with a High Back Pressure Turbine in Fossil Fuel Units.

1000 MWe MODIFIED CONVENTIONAL TURBINE
(FOR STUDY PURPOSES ONLY)

Note: Based on conventional turbine at 3.5 in. Hg absolute with a net heat rate of 8047 BTU/KW-HR.

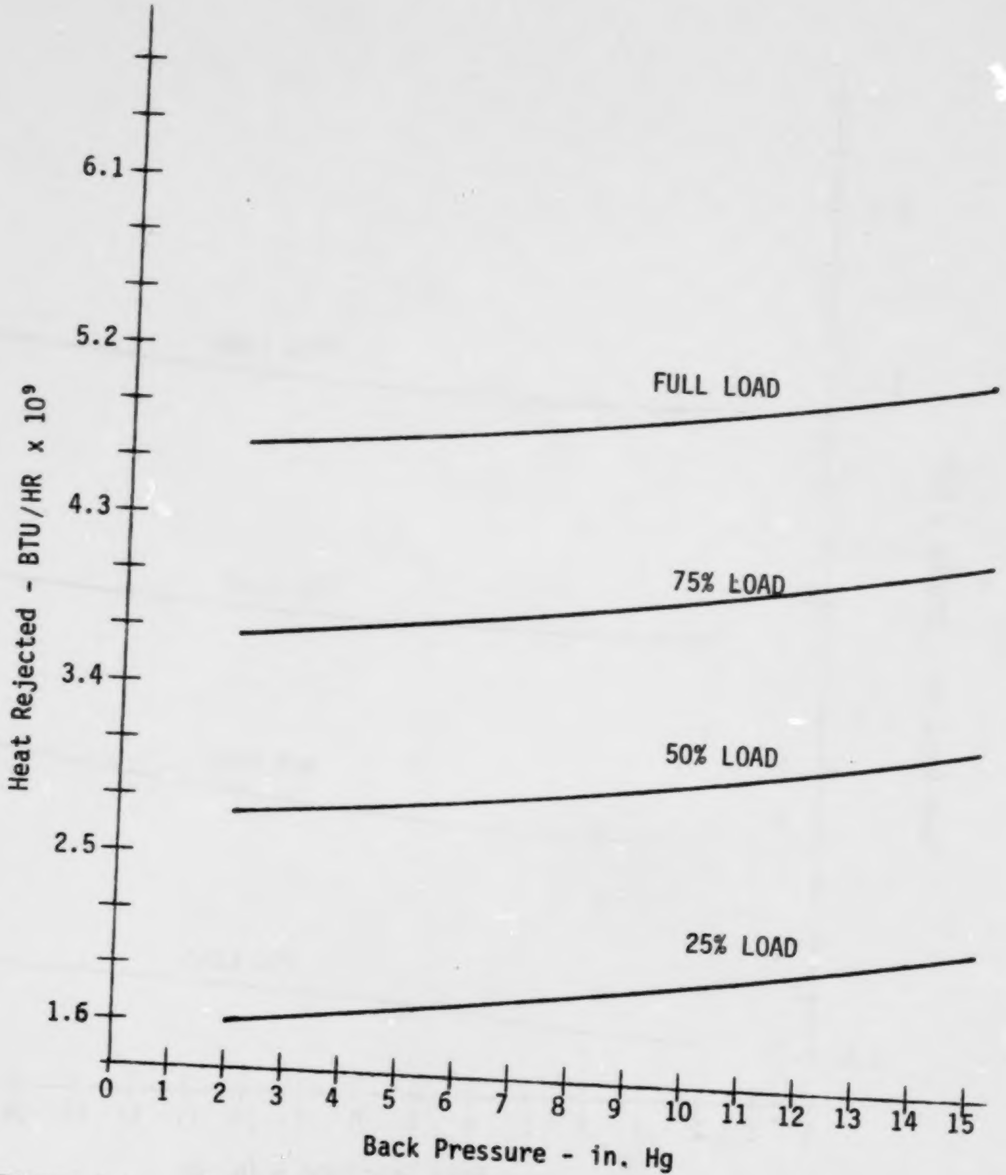

Figure A.4. Net Heat Rejected for Modified Conventional Turbines in Fossil Fuel Units.

1000 MWe HIGH BACK PRESSURE TURBINE
(FOR STUDY PURPOSES ONLY)

Note: Based on conventional turbine at 3.5 in. Hg absolute with a net heat rate of 8047 BTU/KW-HR.

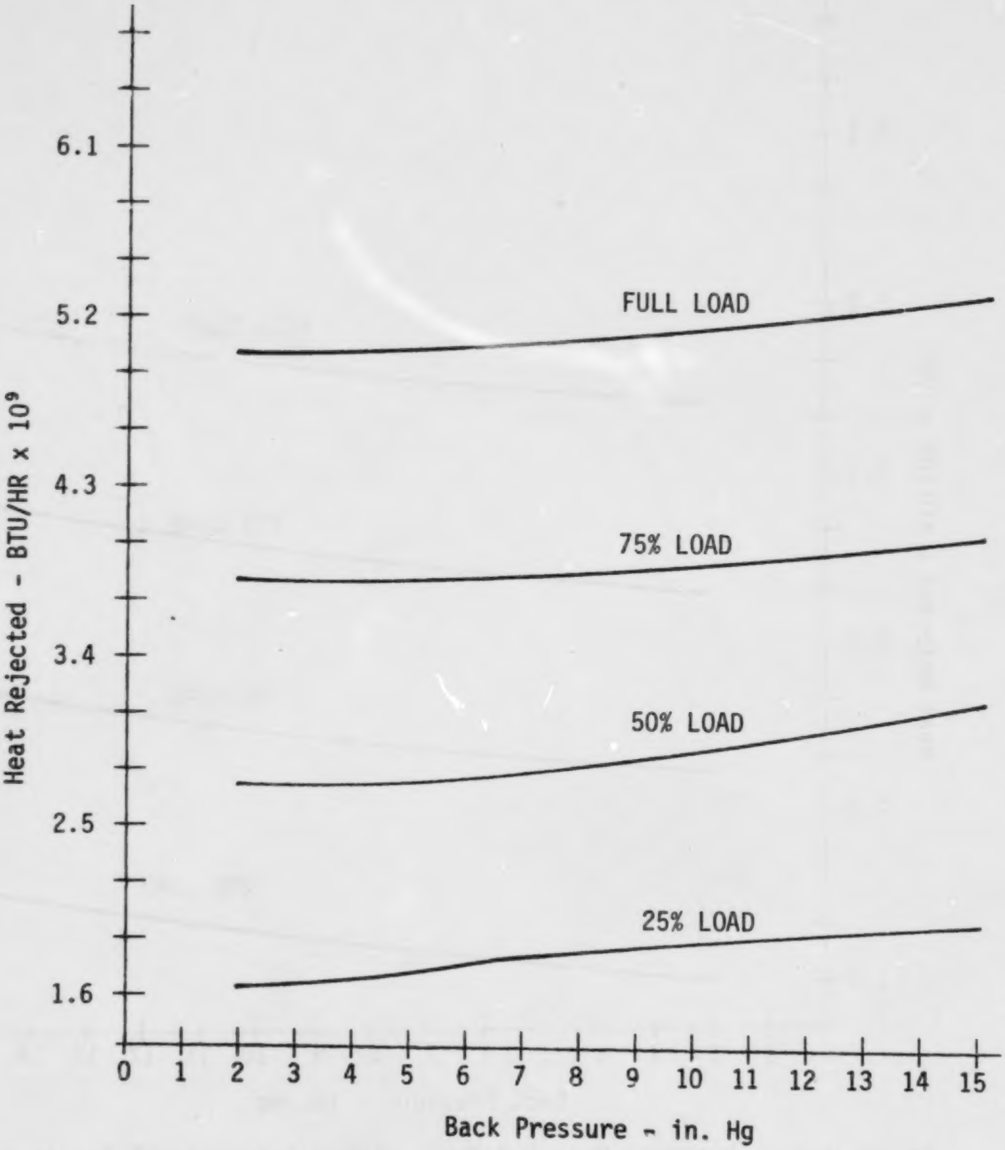

Figure A.5. Net Heat Rejected for High Back Pressure Turbines in Fossil Fuel Units.

APPENDIX B

Description of the multicomponent optimization technique used in this study.

The Multicomponent Optimization

The basic method of optimization for the dry cooling tower system is the M.J. Box Complex Method (16). This method is a sequential search technique that was chosen due to the nature of the non-linear, constrained variables that make up the cost function of a cooling tower system. In addition, the Box Method requires a fewer number of cost calculations as compared with the factorial, "shotgun", or univariate methods. The basic Box procedure was employed, but some modifications were implemented to better accomodate the dry cooling tower project.

The Box Method minimizes a function,

$$F(X_1, X_2, X_3, \ldots\ldots, X_N)$$

by finding the optimum combination of the independent variables. The independent variables along with certain implicit variables are subject to the following constraints:

$$G_k \leq X_k \leq H_k \qquad k = 1, 2, 3, \ldots\ldots, M$$

The lower and upper constraints, G_k and H_k, are either constants or functions of the independent variables. The implicit variables, X_{N+1} through X_M, are dependent functions of the independent variables.

The procedure is as follows:

1. Randomly pick an initial complex of points such that all constraints are satisfied. Each point is a set of the independent variables and a complete design, rating, and costing of the cooling tower is performed for each point.

2. Find the j^th point in the complex with the highest cost function and replace it with a new point. The new point is found by:

   $$X_{ij} = \overline{X}_i + \alpha\,(\overline{X}_i - X_{ij}) \qquad \text{(B-1)}$$

   where $\overline{X}_i$ is the centroid of the i^{th} independent variable and α is an expansion factor which is greater than 1. For this study a value of 2 was used for α. The centroid is the average of the i^{th} independent variable of all the points, excluding the point that is being replaced.

3. Check to see if all the independent variables of the new point satisfy their respective constraints. If an explicit constraint is violated, that particular variable is placed a small distance, δ, from the boundary. If an implicit constraint is violated, the variable is moved half of the distance to its centroid.

4. If the point repeats as the one with the highest cost function, then all of the independent variables are moved half of the distance to their centroids.

5. This procedure continues until there is no further reduction of the cost function. The criterion for termination depends on the user.

The cooling tower design is characterized by N = 6 independent variables (the number of tube rows and passes is fixed for a given design). They are:

Q = the heat rejected in the cooling tower.

ITD = the difference between the ambient temperature and the hot water temperature entering the cooling tower.

RANGE = the difference between the temperature of the water entering and the temperature of the water leaving the cooling tower.

TL = length of the tubes.

TN = number of tubes for the entire cooling tower.

TTD = the difference between the saturation temperature of the steam in the condenser and the temperature of the water leaving the condenser.

The constraints used for the cooling tower variables are as follows:

$\mathrm{QMIN} \leq \mathrm{Q} \leq \mathrm{QMAX}$

$\mathrm{ITDMIN} \leq \mathrm{ITD} \leq \mathrm{ITDMAX}$

$\mathrm{RNGMIN} \leq \mathrm{RANGE} \leq \mathrm{MIN(RNGMAX, ITD)}$

$\mathrm{TLMIN} \leq \mathrm{TL} \leq \mathrm{TLMAX}$

$\mathrm{TNMIN} \leq \mathrm{TN} \leq \mathrm{TNMAX}$

$\mathrm{TTDMIN} \leq \mathrm{TTD} \leq \mathrm{TTDMAX}$

The minimum and maximum values used for this study depended on what case was being studied. In general, Q varied from 4678 MMBTU/HR up to 5401 MMBTU/HR. ITD varied from 20^{o}F up to 80^{o}F. TL varied from 40 ft. up to 80 ft. TN varied from 50,000 tubes up to 200,000 tubes. Finally, TTD varied from 2^{o}F up to 15^{o}F.

In addition to the 6 independent variables, the Box procedure must constrain the 2 dependent variables, air-side and tube-side velocity.

When a dependent variable constraint is violated, the value of TN or TL is changed such that the dependent variable rests on the limit. If the tube-side velocity constraint is violated, the value of TN is changed. If air-side velocity constraint is violated, the value of TL is changed. The criterion for an optimal solution is for all the points to have cost functions that lie within a specified tolerance of each other and continue to do so for a specified number of iterations.

APPENDIX C

Flow Chart of the
Dry Tower Optimization Program.

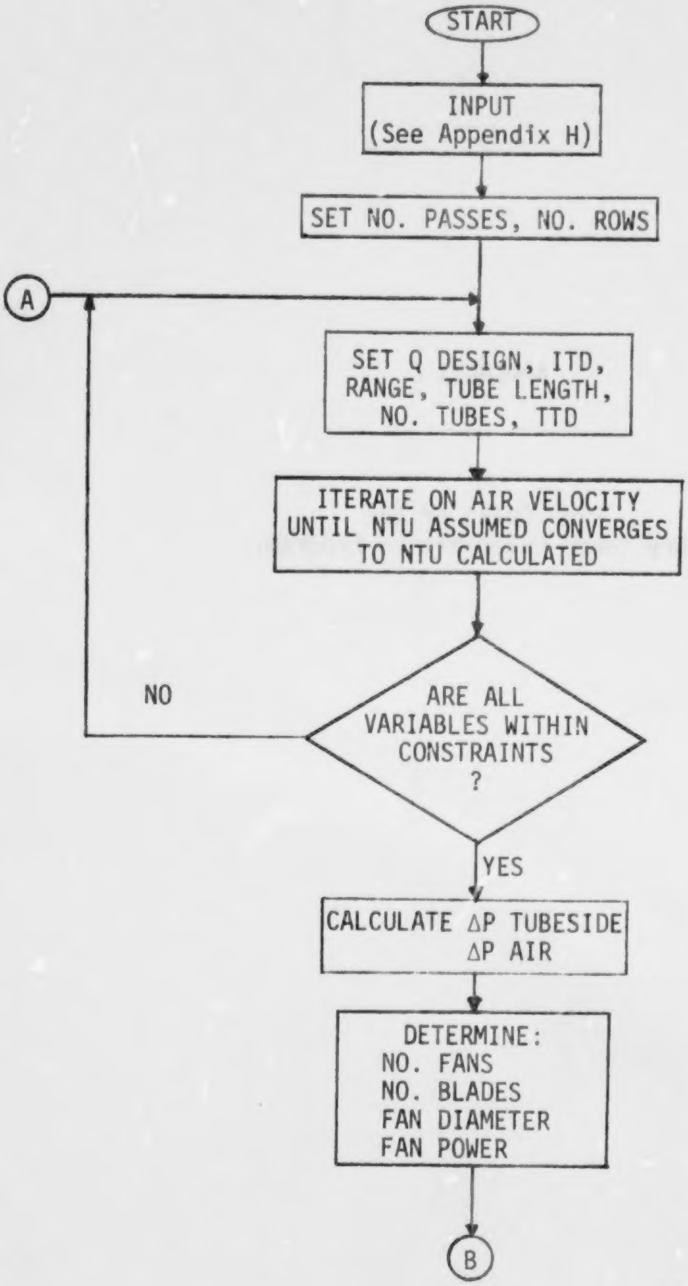
START
INPUT (See Appendix H)
SET NO. PASSES, NO. ROWS
A
SET Q DESIGN, ITD, RANGE, TUBE LENGTH, NO. TUBES, TTD
ITERATE ON AIR VELOCITY UNTIL NTU ASSUMED CONVERGES TO NTU CALCULATED
NO
ARE ALL VARIABLES WITHIN CONSTRAINTS ?
YES
CALCULATE ΔP TUBESIDE ΔP AIR
DETERMINE: NO. FANS NO. BLADES FAN DIAMETER FAN POWER
B

Figure C.1. Flow Chart of Cooling System Optimization.

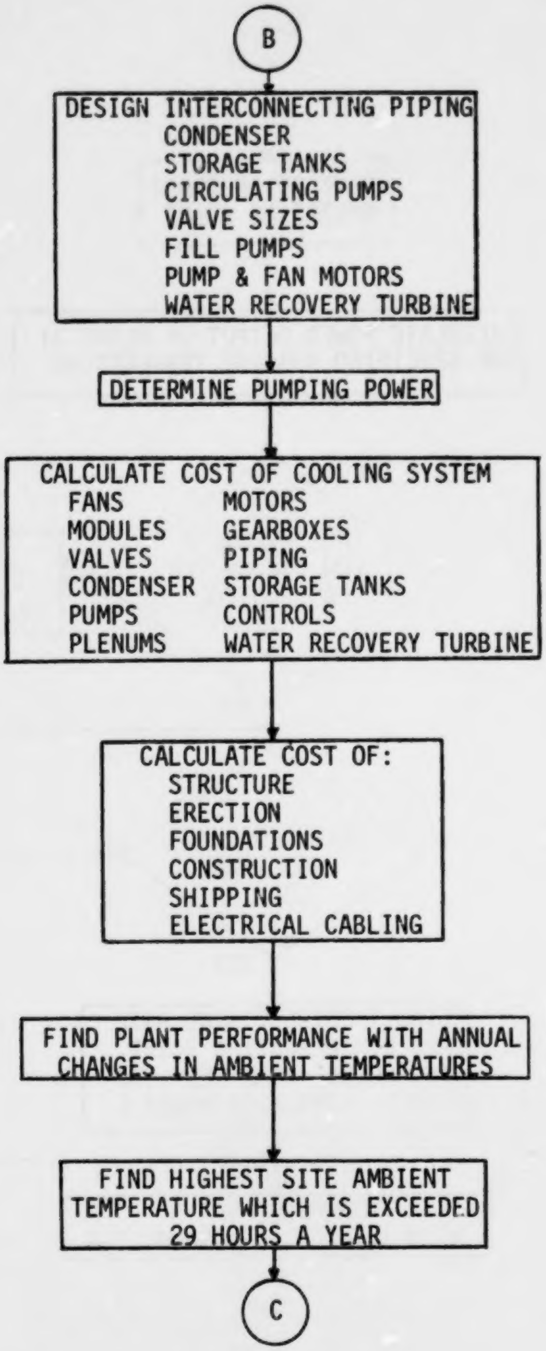
B
DESIGN INTERCONNECTING PIPING
CONDENSER
STORAGE TANKS
CIRCULATING PUMPS
VALVE SIZES
FILL PUMPS
PUMP & FAN MOTORS
WATER RECOVERY TURBINE
DETERMINE PUMPING POWER
CALCULATE COST OF COOLING SYSTEM
FANS
MOTORS
MODULES
GEARBOXES
VALVES
PIPING
CONDENSER
STORAGE TANKS
PUMPS
CONTROLS
PLENUMS
WATER RECOVERY TURBINE
CALCULATE COST OF:
STRUCTURE
ERECTION
FOUNDATIONS
CONSTRUCTION
SHIPPING
ELECTRICAL CABLING
FIND PLANT PERFORMANCE WITH ANNUAL CHANGES IN AMBIENT TEMPERATURES
FIND HIGHEST SITE AMBIENT TEMPERATURE WHICH IS EXCEEDED 29 HOURS A YEAR
C

Figure C.1 (cont'd.).

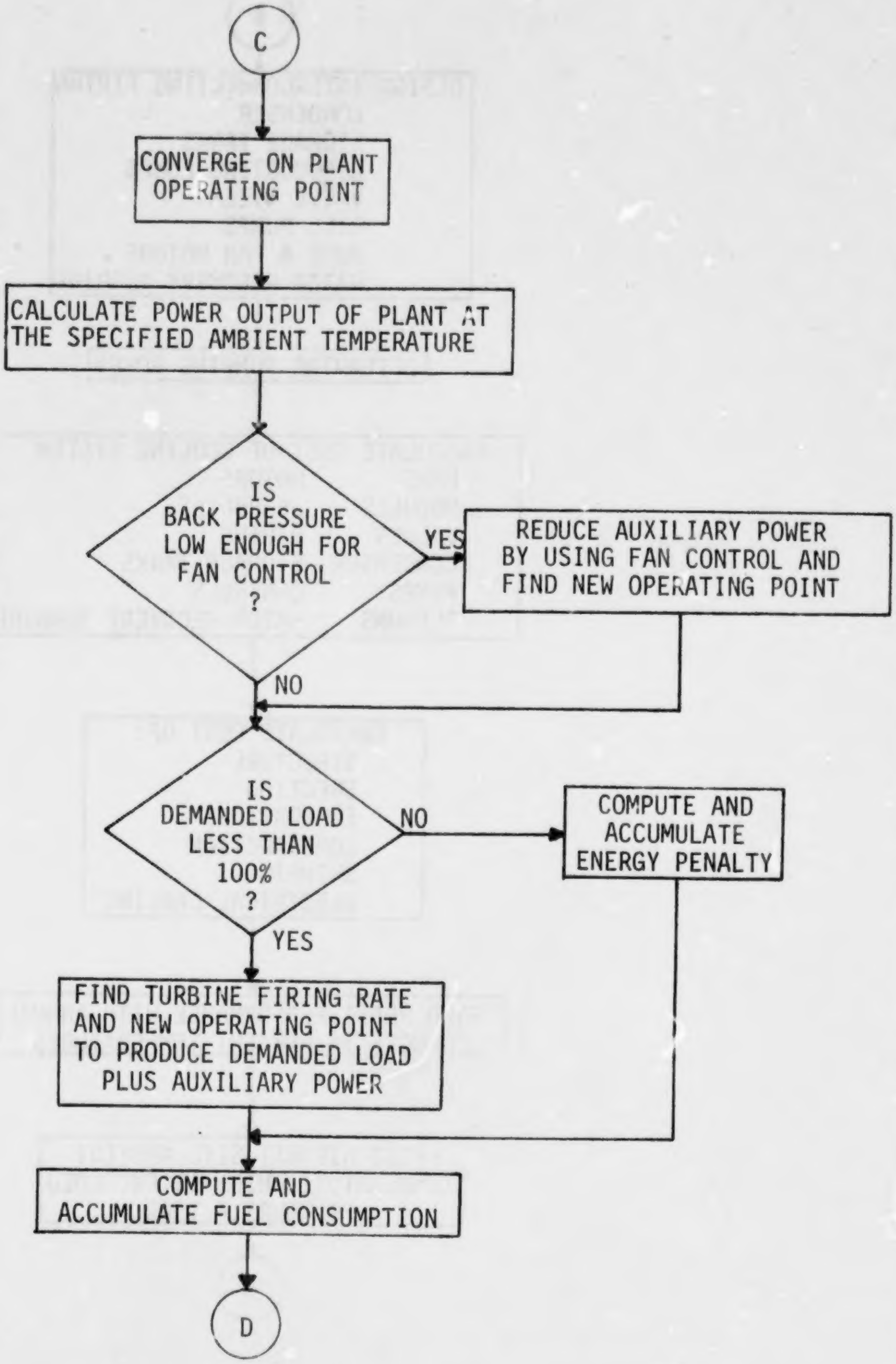
C
CONVERGE ON PLANT OPERATING POINT
CALCULATE POWER OUTPUT OF PLANT AT THE SPECIFIED AMBIENT TEMPERATURE
IS BACK PRESSURE LOW ENOUGH FOR FAN CONTROL ?
YES
REDUCE AUXILIARY POWER BY USING FAN CONTROL AND FIND NEW OPERATING POINT
NO
IS DEMANDED LOAD LESS THAN 100% ?
NO
COMPUTE AND ACCUMULATE ENERGY PENALTY
YES
FIND TURBINE FIRING RATE AND NEW OPERATING POINT TO PRODUCE DEMANDED LOAD PLUS AUXILIARY POWER
COMPUTE AND ACCUMULATE FUEL CONSUMPTION
D

Figure C.1 (cont'd.).

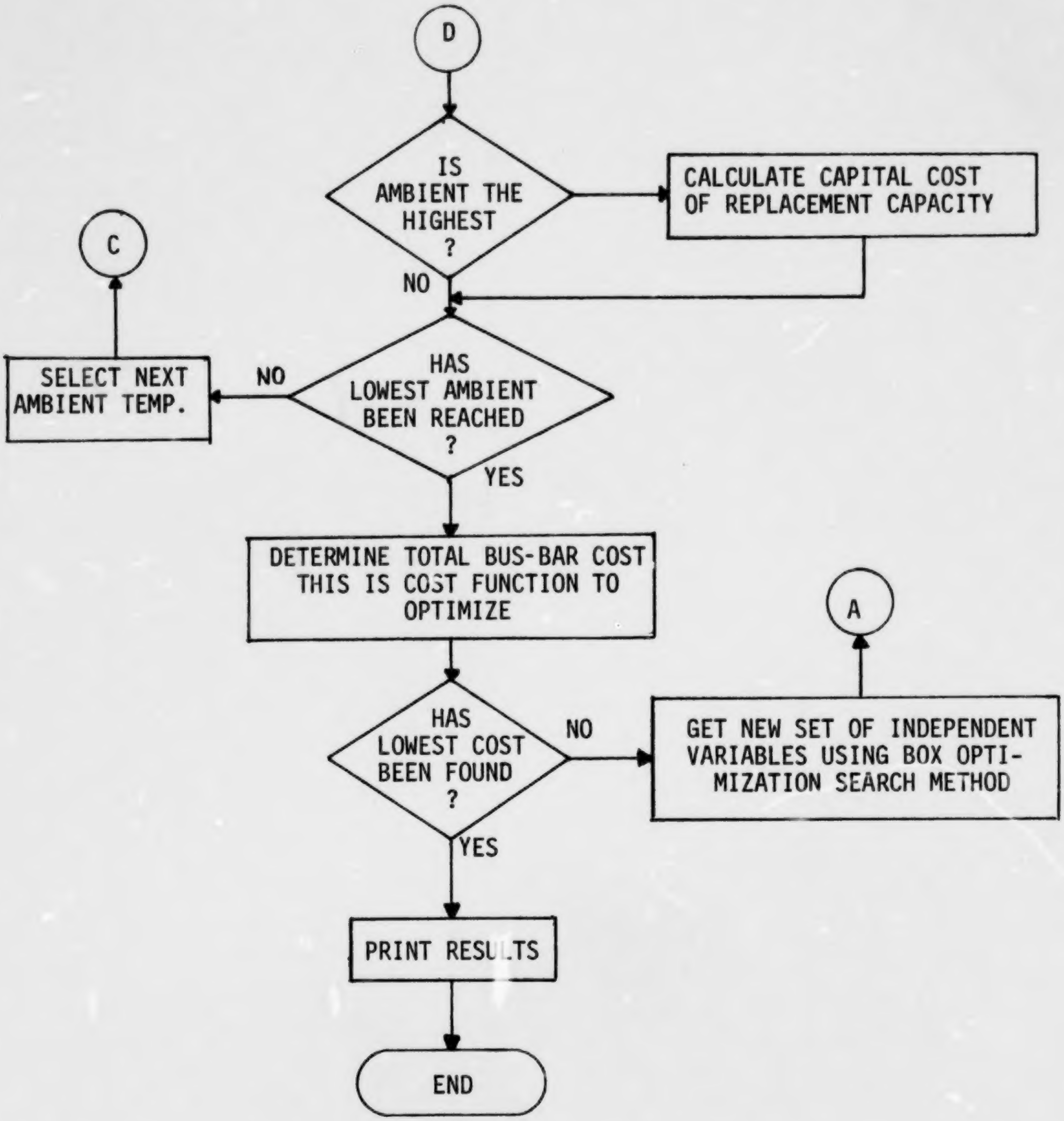
D
IS AMBIENT THE HIGHEST ?
CALCULATE CAPITAL COST OF REPLACEMENT CAPACITY
NO
C
SELECT NEXT AMBIENT TEMP.
NO
HAS LOWEST AMBIENT BEEN REACHED ?
YES
DETERMINE TOTAL BUS-BAR COST THIS IS COST FUNCTION TO OPTIMIZE
A
HAS LOWEST COST BEEN FOUND ?
NO
GET NEW SET OF INDEPENDENT VARIABLES USING BOX OPTIMIZATION SEARCH METHOD
YES
PRINT RESULTS
END

Figure C.1 (cont'd.).

APPENDIX D

Ambient Temperature Profiles for the Sites Studied in this Work.

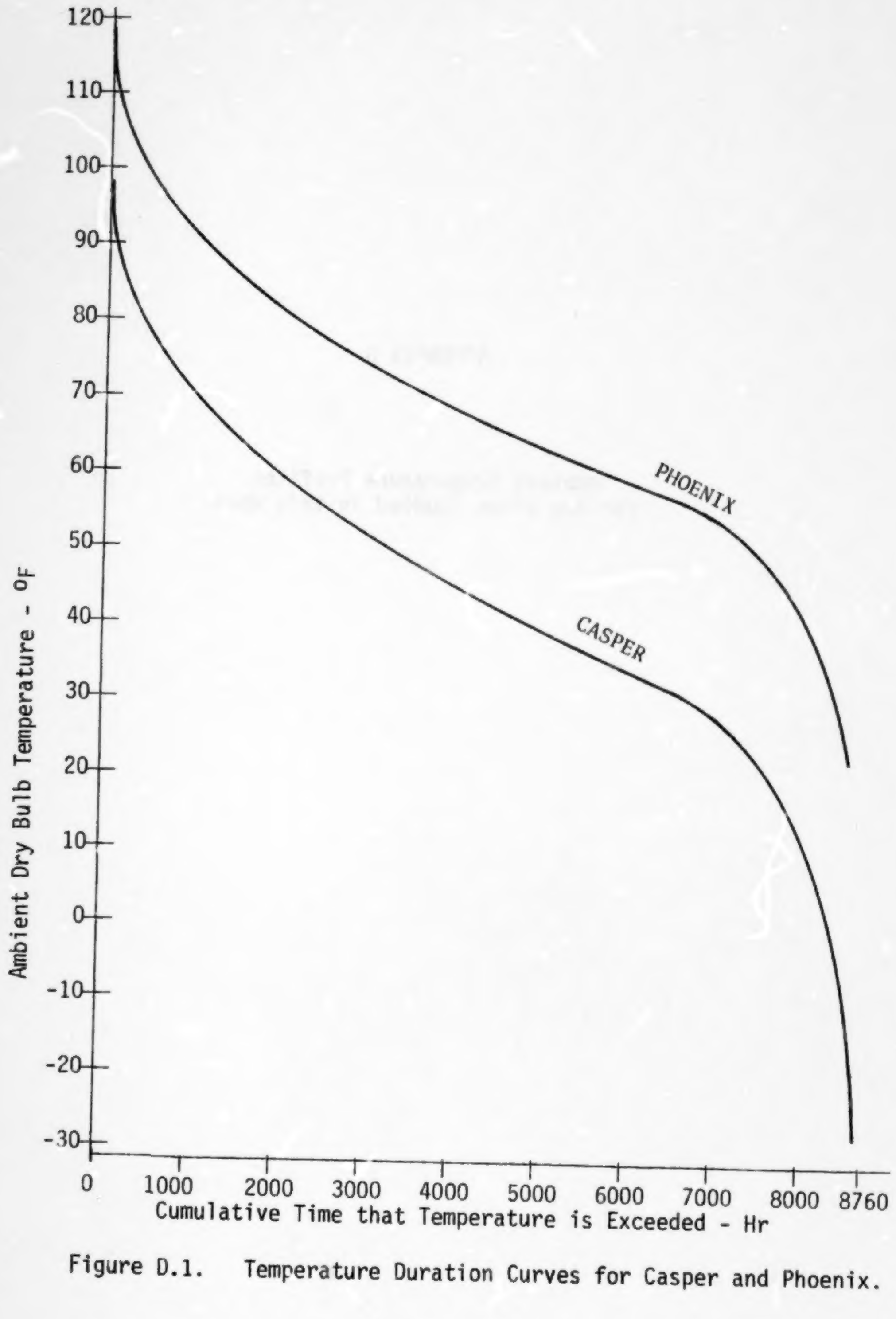

Figure D.1. Temperature Duration Curves for Casper and Phoenix.

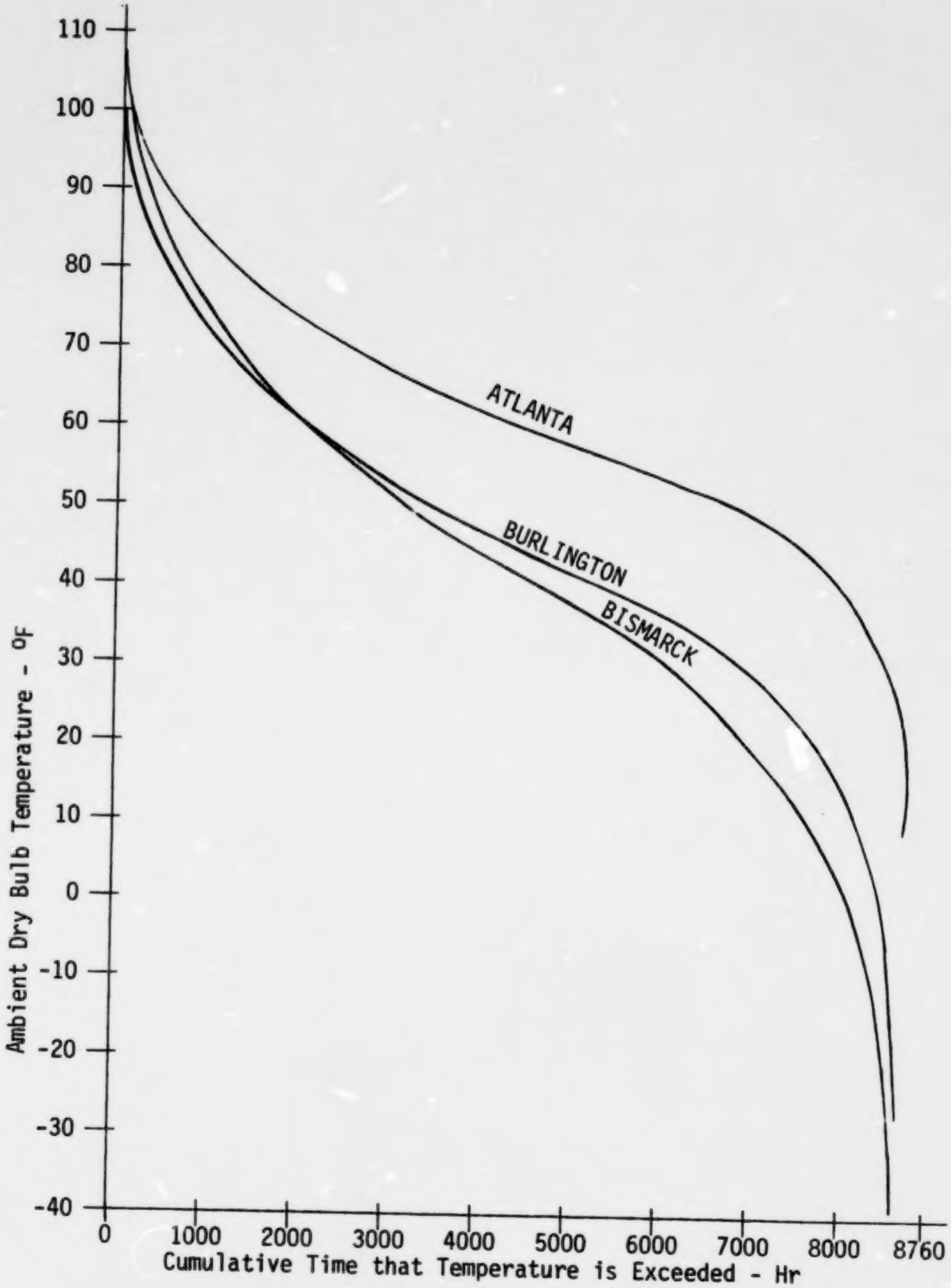

Figure D.2. Temperature Duration Curves for Atlanta, Burlington and Bismarck.

APPENDIX E

Sample Computer Output
for an Optimal System.

TABLE E-1. INPUT FOR 1000 MWe MODIFIED CONVENTIONAL STEAM TURBINE

```
**THE FIRST 4 COLUMNS ARE HEAT RATE - BTU/KW-HR
***THE LAST 4 COLUMNS ARE HEAT REJECT - MMBTU/HR
*LOAD*
        1.00     .75     .50     .25    1.00     .75     .50     .25

 BP - in. Hg
 --
 2.0   8935.   9057.   9560.  10448.   4678.   3620.   2698.   1595.
 2.5   8957.   9094.   9647.  10648.   4687.   3630.   2714.   1612.
 3.0   8990.   9149.   9789.  10905.   4699.   3646.   2739.   1633.
 3.5   9031.   9225.   9936.  11127.   4714.   3667.   2765.   1650.
 4.0   9084.   9322.  10067.  11305.   4735.   3694.   2787.   1664.
 4.5   9146.   9425.  10196.  11461.   4758.   3721.   2808.   1675.
 5.0   9218.   9527.  10323.  11616.   4784.   3748.   2829.   1686.
 5.5   9294.   9625.  10403.  11761.   4811.   3773.   2841.   1696.
 6.0   9372.   9719.  10570.  11917.   4839.   3797.   2867.   1707.
 6.5   9444.   9810.  10688.  12072.   4864.   3820.   2885.   1717.
 7.0   9516.   9900.  10804.  12229.   4889.   3841.   2902.   1727.
 7.5   9586.   9988.  10915.  12384.   4912.   3863.   2918.   1737.
 8.0   9655.  10073.  11027.  12540.   4935.   3882.   2934.   1746.
 8.5   9725.  10159.  11138.  12695.   4958.   3902.   2949.   1756.
 9.0   9791.  10242.  11249.  12851.   4980.   3921.   2964.   1765.
 9.5   9858.  10326.  11361.  13008.   5001.   3940.   2979.   1774.
10.0   9926.  10409.  11471.  13163.   5023.   3958.   2993.   1782.
10.5   9994.  10491.  11583.  13319.   5044.   3976.   3007.   1791.
11.0  10060.  10570.  11694.  13474.   5064.   3993.   3021.   1799.
11.5  10126.  10654.  11806.  13631.   5084.   4010.   3035.   1807.
12.0  10191.  10737.  11917.  13786.   5103.   4027.   3048.   1815.
12.5  10255.  10815.  12028.  13942.   5122.   4043.   3062.   1823.
13.0  10319.  10893.  12139.  14097.   5141.   4059.   3075.   1830.
13.5  10382.  10971.  12250.  14253.   5159.   4074.   3087.   1837.
14.0  10446.  11049.  12362.  14409.   5177.   4089.   3100.   1845.
14.5  10509.  11127.  12473.  14565.   5195.   4105.   3112.   1852.
15.0  10573.  11205.  12585.  14721.   5212.   4119.   3124.   1859.

MINIMUM BACK PRESSURE AT ABOVE LOADS
        3.60    2.90    2.00    2.00

COMPARATIVE HEAT RATE AT ABOVE LOADS TO
DETERMINE INCREMENTAL FUEL COST
        8887.   9021.   9396.   9827.
```

TABLE E-2. SAMPLE COMPUTER OUTPUT OF SURFACE CONDENSER DESIGN

```
** STEAM CONDITIONS
   TOTAL FLOW LEAVING        4.967 MMLB/HR           2.253  MMKG/HR
   SATURATION TEMP.        121.89 DEG.F             49.94  DEG.C
   SATURATION PRESSURE       3.63 IN. HG Abs.       12289   N/M2

** MULTIPRESSURE DESIGN        Btu/hrFt² °F               °F        °F       °F
              SATURATION     OVER.     FRAC.    INLET     TEMP.
   Press. - in. Hg Abs. TEMP-°F COEFF.  DUTY     TEMP.     RANGE    LMTD
   ZONE 1     2.88     113.6  498.61     .45      92.6      10.9    14.9
   ZONE 2     4.38     128.8  513.98     .55     103.5      13.4    17.8

** CIRCULATING WATER CONDITIONS
   FLOW RATE               194.386 MMLB/HR          88.173 MMKG/HR
   TEMP.ENTERING            92.56 DEG.F             33.64 DEG.C
   TEMP.LEAVING            116.89 DEG.F             47.16 DEG.C

** OVERALL PERFORMANCE
   HEAT DUTY              4719.003 MMBTU/HR       1189.169 MMKCAL/HR
   MEAN TEMP.DIFF.          16.33 DEG.F              9.07 DEG.C
   CLEANINESS FACTOR                        .850

** DESIGN RESTRAINTS                   MINIMUM               MAXIMUM
   TUBE SIDE VELOCITY FT/SEC             6.00                  7.00
   TUBE SIDE PRESSURE DROP PSI                                15.00
   TUBE LENGTH FT                       20.00                 80.00
   SATURATION PRESSURE,IN. HG Abs.       2.00                 15.00

** DESIGN   PARAMETERS
   PLATE MATERIAL  CARBON STEEL
   TUBE  MATERIAL  CARBON STEEL
   TUBE     GAUGE            16.

DESIGN  TUBE INFORMATION        NO.OF  NO.OF  TUBE SIDE      OVERALL    TOTAL     COST  ESTIMATED
 NO.    O.D  LENGTH  NUMBER     TUBE   SHELL  PRESS VELOC.   COEFF.     SURFACE   M-$   TOTAL
                                PASSES SER.   DROP           SERVICE    AREA            WEIGHT(TONS)
  4.  1.000   66.0   30107.       1.     1.   7.893   7.0    546.874   520211.2  1033.    1354.
  7.  1.125   78.0   23017.       1.     1.   7.961   7.0    538.557   528765.7  1037.    1431.
  8.  1.125   75.0   24788.       1.     1.   6.700   6.5    518.966   547549.7  1043.    1484.
```

TABLE E-3. SAMPLE COMPUTER OUTPUT OF DRY TOWER TUBE BUNDLE DESIGN

```
                                                          AIR COOLER COST
TOTAL INSTALLED COST PER UNIT
                                                       $ 26847270.41
-------------------------------------------------------------------------------------------------------------

                                                  HEAT EXCHANGER DESIGN VARIABLES
 CASE ID
 NO. OF BAYS IN PARALLEL          DRY TOWER  1
                                             76                        FIELD ERECT UNIT
                                                                       NO. OF BUNDLE SECTIONS IN PARALLEL  228
-------------------------------------------------------------------------------------------------------------
 TUBE BUNDLE INFORMATION

     BUNDLE LENGTH (FT)                  80.00
     TOTAL NUMBER OF TUBES              405                            LONGITUDINAL PITCH    (IN)          2.1649
     NUMBER OF TUBE ROWS                  6                            TRANSVERSE   PITCH    (IN)          2.5000
     NUMBER OF TUBE PASSES                8                            TUBE INSIDE  DIAMETER (IN)           .83
                                                                       TUBE OUTSIDE DIAMETER (IN)          1.00
     TUBE TYPE            ROUND WELDED C.S.
     FIN  TYPE           ALUMINUM L FIN                                FIN HEIGHT            (IN)
     NO. OF FINS PER INCH           10.0                               FIN THICKNESS         (IN)          .6250
-------------------------------------------------------------------------------------------------------------
                                                                       WEIGHT OF FIN AND TUBE (LB/FT)      .0180
 MECHANICAL EQUIPMENT                                                                                      1.567
  FAN TYPE,                                                                                  
     NO./BAY,          AUTO VAR       MOTOR TYPE,    A/C  3600 RPM       TRANSMISSION TYPE,    GEARBOX
     DIAMETER (FT)        2                NO./BAY,          2                     NO./BAY,           2
     NO.BLADES/FAN     32.00          POWER/MOTOR -OPERATING 157.75
                          8                       -INSTALLED 175.00
-------------------------------------------------------------------------------------------------------------
 STRUCTURE HEIGHT (FT)             77.82
-------------------------------------------------------------------------------------------------------------
-------------------------------------------------------------------------------------------------------------
```

TABLE E-4. SAMPLE COMPUTER OUTPUT OF DRY TOWER PIPING COST SUMMARY

```
                                 DIAMETER     TOTAL        SYSTEM
                                   (IN)        ($)          TOTAL
A BAY PIPING                     --------------------
  1. INLET FEEDER LINE              15.25      4582.
  2. OUTLET FEEDER LINE             15.25      3496.
  3. INLET HEADER                   10.14      4136.
  4. OUTLET HEADER                  10.14      4136.
                                             ---------
     PIPING/BAY                               16349.
       76. BAYS                                            1242558.
B SUPPLY PIPING(TYPE 1)
  1.                               114.00    357144.
  2.                                78.00    129581.
  3.                                23.25     30160.
  4.                                72.00    111428.
  5.                                60.00     92132.
  6.                                78.00         0.
                                             ---------
                                             720444.      720444.

C RETURN PIPING(TYPE 1)
  1.                               114.00    361555.
  2.                                60.00    208946.
  3.                                17.25     43245.
  4.                                48.00    122060.
  5.                                41.00    101669.
  6.                                78.00     30281.
                                             ---------
                                             867757.      867757.

D FILL LINES                        19.25     59070.       59070.

E BYPASS LINES                     114.00     27175.       27175.

F VALVING(INSTALLED)
  1. BAY CONTROL                    15.25    594971.
  2. COND. PUMP ISOLATION          114.00    116000.
  3. RECVRY TURBINE ISO.           114.00    116000.
  4. BYPASS                        114.00    174000.
  5. FILL PUMP ISOLATION            19.25     10461.
  6. FILL DRAIN                     19.25     10461.
                                             ---------
                                            1021892.     1021892.

G PUMPS(INSTALLED)
  1.  5  82700. GPM COND.                   1328050.     1328050.
  2.  1   10000 GPM FILL                      20000.       20000.

H STORAGE TANK(INSTALLED)
   4 -  120701. GAL TANKS                   1473331.     1473331.

I CONTROLS(INSTALLED)                       1931245.     1931245.
J NITROGEN BLANKETING                         13350.       13350.
K SHIPMENT OF PIPING                         185399.      185399.
                                                         ---------
                                                         8890271.
```

*NOTE: See Figure 4.7 for a description of the supply and return piping and what the type and numbers refer to.

TABLE E-5. SAMPLE COMPUTER OUTPUT OF OPTIMUM DRY TOWER DESIGN

```
  ** PRINTOUT OF OPTIMUM DESIGN GENERATED BY THE PFR OPTIMIZATION PROGRAM
  =-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=
   1 SIZE 15- 405- 6-HORIZONTAL INDUCED NBU=228 I      1000 MW FOSSIL FUEL
   2 SURFACE/UNIT EXT/BARE  40515435./ 1881158. I SITE    ATLANTA GEORGIA
   3 HEAT EXCHANGED / MTD   4718.2401/ 19.95    I TURBINE  MODIFIED CONV.
   4 RATE EXT/BARE/CLEAN     5.84/125.70/135.94 I CONDENSR         SURFACE
  =-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=
  ** TUBE SIDE  **    ** PROCESS AND PERFORMANCE DATA PER UNIT **
   5 FLUID CIRCULATED          CONDEN.WATER          ENTERING
   6 TOTAL FLUID                  (M-LB/HR)        194385.545        LEAVING
   7   LIQUID                     (M-LB/HR)        194385.545
   8 TEMPERATURE                   (DEG.F)         194385.545     194385.545
   9 PRESSURE                       (PSIA)              116.9           92.6
  10 PRESSURE DROP SPEC./CALC.       (PSI)              26.38          16.00
  =-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=0.00-=-=-=10.38
  ** AIR SIDE **
  11 AIR/UNIT (M-LB/HR)  652321.86   TEMP. IN/OUT   (DEG.F)   68.5/  98.6
  12 AIR/FAN     (ACFM) 1044359.02   ALTITUDE           (FT)           1050.
† 13 FACE VEL    (SFPM)    576.740   STATIC D.P.,CALC.  (IN-H2O)       .6119
  14 MASS V (LB/HR-FT2)   5088.879   STATIC D.P.,SPEC.  (IN-H2O)      0.0000
  =-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=
  ** CONSTRUCTION INFO. PER BUNDLE   DESIGN PRESSURE      (PSI)           50.0
  15 BUNDLE WIDTH  (FT)      14.50   NO. TUBE ROWS    6  TUBE PASSES       2
  16 NO. BUNDLES PARA    3 SERIES 1  TUBE INCLINATION  (DEG.)             10.0
  17 NO. BAYS    PARA   76 SERIES 1  HEADER TYPE                          PLUG

  ** TUBE AND FIN INFORMATION **
  18 NO. TUBES/BUNDLE          405   TUBE TYPE        STRAIGHT          FINNED
  19 TUBE OD/ID    (IN) 1.000/ .834  TUBE LAYOUT  30. DEGREES         STAGGERD
  20 FIN OD/THICK (IN) 2.250/ .018   PITCH- TRANSVERSE     (IN)         2.5000
  21 NO. FINS PER  IN.       10.00          - LONGITUD.    (IN)         2.1649
  22 TUBE LENGTH-OVRL (FT)  80.000   FINNING FACTOR                     21.538
  23             -EFF. (FT)  77.816  FIN SURFACE                        SMOOTH
  24 TUBE SHEET THICK.(IN)     2.2   TOTAL SPACER LENGTH (IN)             24.0

  ** FAN EQUIPMENT **
  25 NO. FANS/BAY                 2  POWER/FAN,(EFF=.72) (HP)           157.75
  26 FAN DIAMETER      (FT)  32.000  POWER/FAN,SPEC.      (HP)          175.00
  27 AREA RATIO-     FAN/FACE  .445  PLOT AREA             (FT2)     267062.07
  28 AREA RATIO- X-SECT/FACE   .510  ASPECT RATIO                        0.000
```

† Note: SFPM is defined as ft. per min calculated by using an air density of .075 lbs/ft³.

TABLE E-6. COMPUTER OUTPUT OF SUMMARY OF FINAL DRY TOWER DESIGNS FOR A SAMPLE CASE

```
*** THE FOLLOWING ARE THE OPTIMIZED DESIGNS GENERATED BY THE BOX METHOD
 THEY MAKE UP THE COMPLEX AT THE END OF THE OPTIMIZATION PROCEDURE ***

     Z Z BUND FAN BARE                 TUBE INFORMATION         *  AIRSIDE INFO. *
     B P WDTH  ID SURF.     -------------------------------- -----------------------
     A A          AREA      NO. LGH TEMPS. VEL.  FLOW       TEMPS. VEL  FLOW
     Y N  FT   FT FT**2         FT  IN °F OUT FPS MMLB/HR    IN °F OUT FPM MMLB/HR
------------------------------------------------------------------------------------

 1   72 2 14. 32. 1729345. 393 80 117  89. 4.7 168.39  64  96 586 609.46
 2   72 2 14. 32. 1755747. 399 80 121  93. 4.8 172.20  69 100 604 637.94
 3   76 2 14. 32. 1825420. 393 80 117  91. 4.9 185.18  67  97 596 653.81
 4   80 2 14. 32. 1921494. 393 80 117  93. 5.0 196.55  70  99 587 678.68
 5   72 2 14. 32. 1676541. 381 80 117  88. 4.7 162.84  63  95 610 615.64
 6   76 2 14. 32. 1853289. 399 80 119  93. 4.8 181.71  70  99 607 676.55
 7   76 2 14. 32. 1825420. 393 80 117  92. 5.0 189.68  69  98 624 684.87
 8   76 2 14. 32. 1825420. 393 80 120  94. 4.8 181.88  69 101 572 627.73
 9   68 2 15. 32. 1683141. 405 80 117  88. 4.7 163.40  63  95 602 609.09
10   72 2 15. 32. 1782149. 405 80 118  90. 4.7 173.97  68  97 624 668.47
11   76 2 14. 32. 1825420. 393 80 126  97. 4.4 166.94  75 105 601 660.09
12   80 2 14. 32. 1921494. 393 80 124 100. 5.0 198.20  77 106 586 677.58
13   76 2 15. 32. 1881158. 405 80 117  93. 5.0 194.39  69  99 577 652.32
```

*NOTE: The above designs correspond to the costs given in Table 6-1.

APPENDIX F

Table of
SI Conversions.

TABLE F-1. SI CONVERSIONS FOR TERMS IN BRITISH UNITS

TO OBTAIN	MULTIPLY	BY
J	BTU	1055.06
Kg	lb_m	.45359
Kg/sec	lb_m/hr	1.2600×10^{-4}
Kg/m^2-sec	$lb_m/hr - ft^2$	1.3562×10^{-3}
m	ft	.30484
m/sec	ft/min	$.50800 \times 10^{-2}$
m^3	gal	3.7854×10^{-3}
m^3/sec	gal/min	6.3091×10^{-5}
m^3/sec	ft^3/min	4.7196×10^{-4}
N/m^2	psi	6894.6
N/m^2	ft H_2O	2989.0
N/m^2	in. Hg	3385.3
W	BTU/hr	3.4122
$W/m^2\text{-}^oK$	$BTU/hr\text{-}ft^2\text{-}^oF$	5.6783
W	hp	745.71

OTHER:

To obtain ^oK:

$$T(K) = 273 + 5/9 \{T(F) - 32\}$$

APPENDIX G

Heat Transfer and Pressure Drop Calculations.

HEAT TRANSFER AND PRESSURE DROP CALCULATIONS

The heat transfer method used in this program utilizes the effectiveness - NTU approach to heat exchanger design as developed by Kays and London (14). In this method, the heat load is expressed by the following equation:

$$Q = (M C_p)_{air} \ (ITD)(P) \qquad \text{(G-1)}$$

where,

Q = the total heat load transferred in the heat exchanger.

$(M C_p)_{air}$ = the product of air flow rate and specific heat of air.

ITD = the initial temperature difference between the incoming hot water and the ambient air.

P = thermal effectiveness.

The number of transfer units and capacity ratio, R, are nondimensional numbers which characterize the heat exchanger by its design variables. In the equations used here, it is assumed that $(M C_p)_{water}$ is greater than $(M C_p)_{air}$.

$$NTU = \frac{(U)(A)}{(M C_p)_{air}} \qquad \text{(4-9)}$$

$$R = \frac{(M C_p)_{air}}{(M C_p)_{water}} \qquad \text{(4-10)}$$

U is the overall heat transfer coefficient based on the outside finned surface area.

For a heat exchanger with "countercurrent" (counterflow) or "cocurrent" (parallel) flow configuration, the relationship between P, R, and NTU can be formulated in closed form by integration. Analytical expressions for the above relationship are given by Kays and London (14). For a cross flow configuration with both tube-side and air-side in the "unmixed" flow condition, the relationship cannot be expressed in analytical form. It can be solved numerically by the method of Stevens et al (17). In this program, a numerical procedure has been incorporated into a subroutine that calculates the effectiveness, P, for a specified NTU and R.

The overall coefficient, U, is calculated as the reciprocal of the sum of all the individual resistances to heat transfer:

$$U = 1.0/(1.0/HAIR + RAOI/HIN + RFIN + RTOT) \qquad \text{(G-2)}$$

where,

HAIR = the air-side heat transfer coefficient based on total finned surface area.

RAOI = the ratio of finned surface to inside tube surface.

HIN = the water- or tube-side heat transfer coefficient.

RFIN = the fin resistance

RTOT = the sum of the resistances due to tube wall conductance and inside and outside tube fouling, all based on the finned tube area.

The air-side coefficient, HAIR, was calculated on the basis of the Briggs and Young (23) correlation:

$$\mathrm{HAIR} = 0.904\left(\frac{\mathrm{KA}}{\mathrm{DO}}\right)(\mathrm{REA})^{0.718}(\mathrm{PRAV})^{0.333} \qquad \text{(G-3)}$$

where,

KA = the thermal conductivity of the air in BTU/hr-ft^2-$^{\circ}$F.

DO = the outside tube diameter in in.

REA = the air-side Reynolds number.

PRAV = the air-side Prandtl number.

The Reynolds number was calculated as:

$$\mathrm{REA} = \frac{(\mathrm{DO})(\mathrm{GA})}{(29.04)(\mathrm{MA})} \qquad \text{(G-4)}$$

where,

GA = the air-side mass velocity in $\mathrm{lb_m/hr\text{-}ft^2}$.

MA = the air viscosity in C_p.

The air-side mass velocity was calculated as:

$$\mathrm{GA} = \frac{\mathrm{W2}}{\mathrm{AMIN}} \qquad \text{(G-5)}$$

where,

W2 = the total air-side flow rate in $\mathrm{lb_m/hr}$.

AMIN = the minimum air-side free flow area transverse to air flow in ft^2.

The Prandtl number was calculated as:

$$PRAV = \frac{(2.42)(MA)(CPA)}{KA} \qquad (G\text{-}6)$$

where,

CPA = the air heat capacity in BTU/lb_m-^oF.

The water- or tube-side coefficient, HIN, was calculated from the correlation of Lawrence and Sherwood (18):

$$HIN = 0.7\ (\frac{KW}{DI})\ (REW)^{0.7}\ (PR)^{0.5} \qquad (G\text{-}7)$$

where,

KW = the thermal conductivity of water in BTU/hr-ft^2-^oF.

DI = the inside tube diameter in in.

REW = the tube-side Reynolds number.

PR = the tube-side Prandtl number.

The Reynolds number was calculated as:

$$REW = \frac{(DI)(GW)}{(29.04)(MW)} \qquad (G\text{-}8)$$

where,

GW = the tube-side mass velocity in lb_m/hr-ft^2.

MW = the water viscosity in Cp.

The tube-side mass velocity was calculated as:

$$GW = \frac{W1}{AT} \qquad (G\text{-}9)$$

where,

W1 = the total tube-side flow rate in lb_m/hr.

AT = the inside cross-sectioned area of all tubes in a single tube pass in ft^2.

The Prandtl number was calculated as:

$$PR = \frac{(2.42)(MW)(CPW)}{KW} \qquad (G\text{-}10)$$

where,

CPW = the water heat capacity in BTU/lb_m-^oF.

The fin resistance, RFIN, is a function of fin height and thickness and thermal conductivity of the fin and was calculated by the method developed by Schmidt (19). The sum of the inside and outside tube fouling factors in this study was assumed to be 0.005 hr-ft-°F/BTU, which is the value used by industry for relatively clean conditions. The tube wall resistance was calculated using a value of 26 BTU/hr-ft-°F for the tube thermal conductivity.

The air-side friction loss was determined by using the following correlation which was developed at PFR Engineering Systems, Inc.:

$$\mathrm{DELP} = \frac{(F)(GA)^2(N)}{(GC)(DENA)} \quad (2.68 \times 10^{-10}) \qquad \text{(G-11)}$$

where,

f = the dimensionless friction factor.

N = the number of tube rows in the direction of air flow.

GC = the dimensional gravitational constant of 32.2 $\mathrm{lb_m}$-ft/lbf-sec^2.

DENA = the air density at average temperature in $\mathrm{lb_m/ft^3}$.

DELP = the pressure drop in psi.

The friction factor as developed by PFR is a function of Reynolds number, tube geometry, and tube pitch. The friction factor was defined as:

$$f = (6.03)(REA)^{-0.245}\left(\frac{PT}{DO}\right)^{-0.872}\left(\frac{PT}{PL}\right)^{0.515}(RAOR)^{0.430} \qquad \text{(G-12)}$$

where,

PT = the tube pitch transverse to air flow in in.

PL = the tube pitch in the direction of air flow in in.

RAOR = the ratio of total outside finned surface area to the outside surface area of the bare tube.

In addition to the tube bundle friction loss, the program calculates three additional pressure losses. Each loss uses the actual density corrected for altitude and temperature at the position in the bundle. The momentum loss accounts for contraction and expansion into and out of the dry cooling tower as well as the loss caused by the increase in air temperature as air is heated, producing a higher leaving velocity. The calculation of the total pressure loss also incorporates the dynamic velocity head to find the loss incurred in accelerating the air from zero velocity to the approach velocity and incurred due to the area change at the fan. Finally, the program calculates the loss due to flow through the fan guards and inlet louvers. The equations for these additional pressure losses can be found in Kays and London (14). The program uses a value of 1.8 for the louver loss coefficient, 1.1 for the fan guard loss coefficient, and 4.5 for the dynamic velocity head loss coefficient. The use of these loss coefficients is defined in Kays and London (14).

The tube-side pressure drop is calculated by assuming commercial circular pipe with fouling and using the Fanning friction formulation. The Fanning equation for flow loss in a tube is:

$$\text{DELPN} = \frac{(\phi)(f_{iso})(GW)^2(L)}{(GC)(DENW)(DI)} \quad (1.286 \times 10^{-8}) \qquad \text{(G-13)}$$

where,

DELPN = the pressure drop in psi.

L = the total length of tube in ft.

f_{iso} = the dimensionless isothermal Fanning friction factor.

DENW = the water density at average temperature in lb_m/ft^3.

ϕ = the Sieder-Tate (20) correction factor for bulk to wall property variation.

Both f_{iso} and ϕ are defined differently depending on whether or not the flow is laminar, in transition, or turbulent. The expressions for f_{iso} were found by fitting curves to the 3 zones of the Moody (21) chart and dividing by 4 to determine the Fanning friction factor.

To determine the total dry cooling tower pressure drop, in addition to the tube-side friction loss, the program calculates the inlet nozzle loss using a loss coefficient, k, of 1.0; the inlet header contraction loss using a k of 1.5; the turn-around loss between passes using a k of 1.5; the outlet header expansion loss using a k of .25, and the outlet nozzle loss using a k of 0.5. The pressure drop for each of these losses is:

$$\text{DEL} = \frac{(k)(GW)^2}{(DENW)(1.20 \times 10^{11})} \qquad \text{(G-14)}$$

where,

DEL = the pressure loss in psi.

k = the loss coefficient.

For the nozzle losses, GW is calculated based on the inside cross-sectional area of the nozzle.

The pressure losses due to the rest of the circulating system have been discussed in detail in earlier sections. The return and supply piping losses were determined by converting all straight lengths, elbows, valves, etc. to equivalent lengths in pipe diameters L/D. The sum of all the L/D s was used in equation G-13 assuming an average DENW and GW and a constant value of 0.00275 for the product of f_{iso} and ϕ. No loss coefficients were used in calculating these pressure losses. The values used for the L/D s of the elbows, valves, etc. can be found in Crane (24). The program actually sums up each pipe, elbow, valve, etc. that is contained in the circulating system. Thus, the elements that are included in the determination of the pressure drop will depend heavily on the design of the system as described in earlier sections.

APPENDIX H

Program Input and Program Listing.

PROGRAM INPUT

The input data required for the Dry Cooling Tower Optimization Program includes an alphanumeric description of the case, the temperature-load profile of the site, site-related design information, parameters for the economic evaluation, and steam turbine performance characteristics. These data are read from standard 80-column computer cards. Integer variables must be right justified and real variables require a decimal point. An explanation of each card is given below.

1. Card No. 1

		Variable Name
Col. 1-2	01 (Card Number)	KNO
Col. 3-22	Case description	BARB(1)-BARB(4)
Col. 23-37	Geographical location or site	BARB(5)-BARB(7)
Col. 38-52	Turbine type	BARB(8)-BARB(10)
Col. 53-67	Condenser type	BARB(11)-BARB(13)

2. Card No. 2

		Variable Name
Col. 1-2	02	KNO
Col. 3-7	Tube inclination in degrees from the horizontal	ANGI
Col. 8-9	Number of tube bundles in parallel in each bay	ZBUP
Col. 10-14	Number of fins/in.	ZNFI
Col. 15-19	The distance in in. between centers of adjacent tubes in a row perpendicular to the air flow direction	PTI
Col. 20-25	Altitude of site in ft.	HALT
Col. 26-29	Fixed charge rate of base plant expressed as a decimal fraction	COST(2)
Col. 30-33	Cost in mills/KW-HR of energy penalty when energy penalty is maximum	COST(6)

		Variable Name
Col. 34-36	Number of tube rows per bundle	ZTRD
Col. 37-40	Number of tube passes per bundle	ZTPD

3. Card No. 3

Col. 1-2	03	KNO
Col. 3-8	Maximum allowable tube length in ft.	TLMAX
Col. 9-13	Minimum allowable ITD in °F	TITDN
Col. 14-17	Decimal fraction used to determine when to stop the optimization procedure (The procedure stops when all designs in the Box Complex have total costs whose ratios are 1.0 ± TOL. Computational time increases as this tolerance is decreased)	TOL
Col. 18-21	Box optimization expansion factor, α (See discussion on Box procedure. Recommended value is 2.0)	ALF
Col. 22-25	Decimal fraction of distance between constraint boundary and centroid to place independent variable when constraint is violated (See discussion on Box procedure. Recommended value is .01)	DELT
Col. 26-28	Maximum number of iterations allowed in Box procedure	ITRMX
Col. 29-31	Number of consectutive iterations which will occur that satisfy the tolerance (card 3, col. 14) before execution stops	NITR
Col. 32-37	Nominal plant capacity in MWe	BCAPC
Col. 38-39	Number of ambient air temperatures to be used (Max. of 20)	NATTR

		Variable Name
Col. 40-44	Cost in $/KWe for capacity replacement	CAPCST
Col. 45-48	Minimum allowable TTD in ^{o}F (Usually 2.0 degrees for direct contact condensers and 5.0 degrees for surface condensers)	TTDMN
Col. 49-52	Maximum allowable TTD in ^{o}F	TTDMX

4. Card No. 4

Col. 1-2	04	KNO
Col. 3-5	Fixed charge rate for capacity replacement expressed as a decimal fraction (In most cases this will be the same as the fixed charge rate for the base plant)	AFCR2
Col. 6-9	Base plant fuel cost in $/MMBTU	FLCST
Col. 10-16	Maximum allowable number of tubes	TNMAX
Col. 17-23	Minimum allowable number of tubes	TNMIN
Col. 24-30	Base heat rate in BTU/KW-HR for load 1 (This is the base heat rate with which to compare the dry tower plant. Incremental fuel is calculated using this base. To use total fuel as a dry tower cost component, input zero. This heat rate corresponds to load 1 (card 11, Col. 6) only)	BHTRT(1)
Col. 31-37	Base heat rate in BTU/KW-HR for load 2	BHTRT(2)
Col. 38-44	Base heat rate in BTU/KW-HR for load 3	BHTRT(3)
Col. 45-51	Base heat rate in BTU/KW-HR for load 4	BHTRT(4)
Col. 52-58	Base heat rate in BTU/KW-HR for load 5	BHTRT(5)

		Variable Name
Col. 59-65	Base heat rate in BTU/KW-HR for load 6	BHTRT(6)

5. Card No. 5

Col. 1-2	05	KNO
Col. 3-7	Maximum allowable air approach velocity in ft/min at standard conditions (Recommended maximum is 700 ft/min)	VAMAX
Col. 8-12	Minimum allowable air approach velocity in ft/min (Recommended minimum is 350 ft/min)	VAMIN
Col. 13-16	Maximum allowable tube-side flow velocity in ft/sec (Recommended maximum is 9 ft/sec)	VWMAX
Col. 17-20	Minimum allowable tube-side flow velocity in ft/sec (Recommended minimum is 2 ft/sec)	VWMIN
Col. 21-25	Maximum allowable cooling range in ^{o}F	RNGMX
Col. 26-30	Minimum allowable cooling range in ^{o}F	RNGMN
Col. 31-35	Maximum allowable ITD in ^{o}F	TITDX
Col. 36-39	Minimum allowable tube length in ft.	TLMIN
Col. 40-43	Maximum allowable flow velocity for the piping system in ft/sec (Recommended maximum is 12.5 ft/sec)	VX
Col. 44-47	Minimum allowable flow velocity for the piping system in ft/sec	VN
Col. 48-51	Installed cost of direct condenser in $/lb/hr of steam flow (Zero indicates a surface condenser is being used)	CONCT

		Variable Name
Col. 52-57	Total installed capital cost of extra steam supply system in millions of dollars	STMCT
Col. 58-62	Ambient air temperature in °F above which maximum energy penalty cost is used (Usually 82°F is used)	CUTMP
Col. 63-67	Cost in mills/KW-HR (Penalty when the energy penalty is minimum)	SHELP
6. Card No. 6		
Col. 1-2	06	KNO
Col. 3-7	Maximum allowable bundle width in ft. (This is usually set by shipping limitations and is a maximum of 14.5 ft.)	WBMAX
Col. 8-12	Maximum allowable inside diameter in in. for piping system (Maximum is 144 in.)	
Col. 13-14	Maximum allowable number of fan blades (Minimum is 8)	MXFBL
Col. 15-18	Maximum allowable fan diameter in ft. (Minimum is 24 ft.)	FDMAX
Col. 19-23	Distance in ft. from power plant to dry cooling towers	DPPCT
Col. 24-27	Distance in ft. from direct contact condenser water level to ground level (If water level is above ground level, input a negative value)	CWTLV
Col. 28-31	Distance in ft. from direct contact condenser spray nozzle level to ground level (If spray nozzles are above ground level, input a negative value)	SPRHT

		Variable Name
Col. 32-36	Pressure drop across direct contact condenser spray nozzles in ft. of water	SPRNZ
Col. 37-42	Maximum shipping length in ft. for piping	SCPMP
Col. 43-46	Back pressure in in. Hg absolute at which steam turbine produces nominal power	PBPHT
Col. 47-49	Efficiency of cooling tower circulating pumps (Usually it is about .89)	CPEFF
Col. 50-52	Overall efficiency of water recovery turbine (Usually it is about .8)	WTEFF
Col. 53-57	Installed cost of water recovery turbine in $/KWe (Input zero if no water recovery turbine is desired)	CWRTI
Col. 58-61	Operating and maintenance cost in mills/KW-HR for the incremental O & M attributable to the heat rejection system	EBPOM

7. Card No. 7

Col. 1-2	07	KNO
Col. 3-7	First ambient air temperature in °F used to rate cooling tower (The first temperature must be the highest ambient temperature and the remaining ambients must be decreasing; this is a requirement for this program)	ATTR(1)
Col. 8-13	Number of hours per year that first ambient air temperature occurs	DATTR(1)

		Varible Name
Col. 14-17	Load factor as decimal fraction of nominal turbine power for determining the plant output desired during the first ambient air temperature	PLDFT(1)
Col. 18-22	Second ambient air temperature	ATTR(2)
Col. 23-28	Number of hours per year for second ambient air temperature	DATTR(2)
Col. 29-32	Load factor for second ambient air temperature	PLDFT(2)
Col. 33-37	Third ambient air temperature	ATTR(3)
Col. 38-43	Number of hours per year for third ambient air temperature	DATTR(3)
Col. 44-47	Load factor for third ambient air temperature	PLDFT(3)
Col. 48-52	Fourth ambient air temperature	ATTR(4)
Col. 53-58	Number of hours per year for fourth ambient air temperature	DATTR(4)
Col. 59-62	Load factor for fourth ambient air temperature	PLDFT(4)
Col. 63-67	Fifth ambient air temperature	ATTR(5)
Col. 68-73	Number of hours per year for fifth ambient air temperature	DATTR(5)
Col. 74-77	Load factor for fifth ambient air temperature	PLDFT(5)

8. Card No. 8

Col. 1-2	08	KNO
Col. 3-77	Same as card No. 7 for ambient air temperatures No. 6 through No. 10 (Columns 3-7 are for ATTR(6), etc.)	

		Variable Name
9. Card No. 9		
Col. 1-2	09	KNO
Col. 3-77	Same as card No. 7 for ambient air temperatures No. 11 through No. 15 (Columns 3-7 are for ATTR(11), etc.)	
10. Card No. 10		
Col. 1-2	10	KNO
Col. 3-77	Same as card No. 7 for ambient air temperatures No. 16 through No. 20 (Columns 3-7 are for ATTR(16), etc.)	
11. Card No. 11		
Col. 1-2	11	KNO
Col. 3-4	Number of turbine back pressures to be used to input turbine information (Maximum is 28)	NBKPR
Col. 5	Number of turbine loads to be used to input turbine information (Maximum is 6)	NLODS
Col. 6-8	Turbine load No. 1 as a decimal fraction of nominal turbine power	XLDFT(1)
Col. 9-11	Back pressure in in. Hg absolute where fan control starts for load 1	BPMNM(1)
Col. 12-14	Turbine load 2	XLDFT(2)
Col. 15-17	Back pressure in in. Hg absolute for fan control for load 2	BPMNM(2)
Col. 18-20	Turbine load 3	XLDFT(3)
Col. 21-23	Back pressure in in. Hg absolute for fan control for load 3	BPMNM(3)

		Variable Name
Col. 24-26	Turbine load 4	XLDFT(4)
Col. 27-29	Back pressure in in. Hg absolute for fan control for load 4	BPMNM(4)
Col. 30-32	Turbine load 5	XLDFT(5)
Col. 33-35	Back pressure in in. Hg absolute for fan control for load 5	BPMNM(5)
Col. 36-38	Turbine load 6	XLDFT(6)
Col. 39-41	Back pressure in in. Hg absolute for fan control for load 6	BPMNM(6)
Col. 42-45	Back pressure No. 1 in in. Hg absolute (The first back pressure for which turbine information will be input)	BP(1)
Col. 46-49	Back pressure No. 2 in in. Hg absolute (The second back pressure for which turbine information will be input)	BP(2)
Col. 50-53	Back pressure No. 3 in in. Hg absolute (The third back pressure for which turbine information will be input)	BP(3)
Col. 54-57	Back pressure No. 4 in in. Hg absolute (The fourth back pressure for which turbine information will be input)	BP(4)
Col. 58-61	Back pressure No. 5 in in. Hg absolute (The fifth back pressure for which turbine information will be input)	BP(5)
Col. 62-65	Back pressure No. 6 in in. Hg absolute (The sixth back pressure for which turbine information will be input)	BP(6)
Col. 66-69	Back pressure No. 7 in in. Hg absolute (The seventh back pressure for which turbine information will be input)	BP(7)

		Variable Name
Col. 70-73	Back pressure No. 8 in in. Hg absolute (The eighth back pressure for which turbine information will be input)	BP(8)
Col. 74-77	Back pressure No. 9 in in. Hg absolute (The ninth back pressure for which turbine information will be input)	BP(9)

12. Card No. 12

Col. 1-2	12	KNO
Col. 3-78	Back pressures No. 10 through No. 28 (One back pressure is placed in every 4 columns)	BP(10) BP(28)

13. Card No. 13

Col. 1-2	13	KNO
Col. 3-7	Heat rate in BTU/KW-HR of plant for load 1 at back pressure No. 1	HTRTD(1,1)
Col. 8-11	Heat rejected in MMBTU/hr by steam turbine for load 1 at back pressure No. 1	HTRJD(1,1)
Col. 12-16	Heat rate in BTU/KW-HR for load 1 at back pressure No. 2	HTRTD(2,1)
Col. 17-20	Heat rejected for load 1 at back pressure No. 2	HTRJD(2,1)
Col. 21-25	Heat rate in BTU/KW-HR for load 1 at back pressure No. 3	HTRTD(3,1)
Col. 26-29	Heat rejected for load 1 at back pressure No. 3 in MMBTU/hr	HTRJD(3,1)

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Continue until all back pressures are done for load 1. Then immediately start load 2 at back pressure number 1. Do this until all loads at all back pressures are entered. Each card should start with the card number in columns 1 and 2 and contain data in column 3 through column 74. Use as many cards as needed, until all back pressures and loads are entered. Do not start a new card when starting a new load, but repeat the same sequence begun for load 1 while using the remaining usable columns on the partially completed card before going to a new card.

APPENDIX I

Program Listing.

```
      PROGRAM MAINA(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)
C *** DRY COOLING TOWER OPTIMIZATION COMPUTER PROGRAM
C *** DEVELOPED BY PFR ENGINEERING SYSTEMS,INC.
C *** LOS ANGELES, CALIFORNIA
C *** JANUARY, 1977
C *** AUTHORS - TZVI ROZENMAN, JAMES M. FAKE, JOSEPH M. PUNDYK
C ***
C *** COMMON VARIABLES USED
C *** PERMANENT INTEGER
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      CALL START
  100 CONTINUE
  200 CALL BOX
C OPTM CONTROLS FINAL OUTPUT PRINTOUTS AND ALT.SOLUTIONS
  300 CALL OUTPT
  400 STOP
      END



      SUBROUTINE ACCOST(TSTS,NTT,NTR,NTP,DTI,DTO,NFPIN,DSL,DST,DHEDW,DL,
     1 DTN1I,DTN1O,NOO1I,NOO1O,DTN2I,DTN2O,NOO2I,NOO2O,ZBUP,ZFAN,DFAN,
     2 NBLD,NMOT,HPMOT,NBPU,DHSTR,KNTR1,CTTOT,CSTOR,DFH,DFT)
C     AIR COOLER COST CALCULATION
      COMMON/FAN/EFFAN,NBLAD,HPMSP
      DIMENSION CASE(3)
      DIMENSION TRATY1(3), TRATY2(3), TRATY3(3), TRATY(3)
      DIMENSION FANTY(2),FANTY1(2),FANTY2(2),FANTY3(2)
      DIMENSION ERT1(7), ERT2(7), ERT3(7), ERT(7)
      DATA CASE /4HDRY ,4HTOWE,4HR  1/
      DATA ERT1 / 4HSHOP,4H ERE,4HCT I,4HNDUC,4HED D,4HRAFT,4HUNIT /
      DATA ERT2 / 4HSHOP,4H ERE,4HCT F,4HORCE,4HD DR,4HAFT ,4HUNIT /
      DATA ERT3 / 4HFIEL,4HD ER,4HECT ,4HUNIT,4H    ,4H    ,4H     /
      DATA FANTY1/4HPERM,4H FIX/
      DATA FANTY2/4HMAN.,4H ADJ/
      DATA FANTY3/4HAUTO,4H VAR/
      DATA TRATY1 / 4HDIRE,4HCT D,4HRIVE /
      DATA TRATY2 / 4HV-BE,4HLT  ,4H     /
      DATA TRATY3 / 4HGEAR,4HBOX ,4H     /
C
C
C
C --- DATA INPUT ----------------------------------------------------
C *** GENERAL ADMINISTRATION COST FACTOR IS ASSUMED AS 1.15
      DATA GAFAC/1.15/
C *** MATERIAL ESCALATION FACTOR IS ASSUMED 1.05
      DATA ESCAL/1.05/
C *** LABOR OVERHEAD FACTOR IS ASSUMED AS 2.0
      DATA OVHDL/2.0/
C *** COST OF ALUMINUM STRIP IS .80 $/LB
      DATA CFIN/.8/
      DATA CPLM1,CPLL1/.25,.5/
      DATA DENCS,DENAL/.2833,.0975/
      DATA TSTOP,TSBOT,TSIDE,TBACK,TSPP/5*0.75/
      DATA CUTT,CUTL,WLDT,WLDL,CHOLE,CASS/2.0,5.0,3.0,5.0,0.65,0.2/
      DATA CTM,CTIB1,DEN/0.25,0.33,0.2833/
      DATA KTUBE,KFIN/0,0/
      DATA CTPG1, ASPG1 / 1.0, 0.5 /
      DATA CTUMT/ 3.0 /
      DATA TSPLM /0.09/
      DATA IDFAN/3/
      DATA MORPM/3600/
C --- --------------------------------------------------------------
C     NBPU  = NUMBER OF BAYS IN PARALLEL PER UNIT
C     NBUP  = NUMBER OF BUNDLES IN PARALLEL PER BAY
C     HPMOT = MOTOR HORSEPOWER
C     NFAN  = NUMBER OF FANS PER BAY
C     DFAN  = FAN DIAMETER (FT)
C     NBLD  = NUMBER OF BLADES PER FAN
C     FPLM  = COST INDEX FOR INSTALLING PLENUM BASED ON PLENUM MATERIAL
C     CPLM1 = UNIT COST FOR PLENUM MATERIAL ($/LB)
C     TSPLM = THICKNESS OF PLENUM (INCH)
C     NMOT  = NUMBER OF MOTORS PER BAY
C
      DLTTK=(DTO+DTI)/2.
C     IF THE NUMBER OF FINS PER INCH NFPIN IS NOT AN INTEGER
C     RUN WITH THE INTEGERS ABOVE AND BELOW TO CALCULATE THE
```

```
C     COST OF THE FINNED TUBES, THEN TAKE AVERAGE VALUE
C
C
      ZTT=NTT
      ZTP=NTP
      NFAN=ZFAN+.01
      ZBPU=NBPU
      ZBLD=NBLD
      ZMOT=NMOT
      Z001I=N001I
      Z001O=N001O
      Z002I=N002I
      Z002O=N002O
C
C
C --- CALCULATE THE FRONT HEADER COST, KTYPE=1
      KTYPE=1
      CALL HEAD(NTT,NTR,NTP,DSL,DST,DHEDW,DTI,DTO,TSTS,TSTOP,TSBOT,TSIDE
     1,TBACK,TSPP,DEN,CTM,CUTT,CUTL,WLDT,WLDL,CHOLE,DTN1I,DTN1O,CTPG1,AS
     2PG1,KTYPE,CTHF,CTCUTF,CTWLDF,CTTPGF,CTFH,SLABF,SMATF,DIF,HIF,DWOF,
     3DHOF,DDOF,NPPF,NPPB)
C
C --- CALCULATE THE BACK HEADER COST, KTYPE=2
      KTYPE=2
      CALL HEAD(NTT,NTR,NTP,DSL,DST,DHEDW,DTI,DTO,TSTS,TSTOP,TSBOT,TSIDE
     1,TBACK,TSPP,DEN,CTM,CUTT,CUTL,WLDT,WLDL,CHOLE,DTN2I,DTN2O,CTPG1,AS
     2PG1,KTYPE,CTHB,CTCUTB,CTWLDB,CTTPGB,CTBH,SLABB,SMATB,DIB,HIB,DWOB,
     3DHOB,DDOB,NPPF,NPPB)
C
C
C --- CALCULATE THE COST OF TUBE BUNDLES, INCLUDING ASSEMBLING
C
      CALL BUNDLE(ZTT,DL,DHOF,DDOF,DDOB,DHEDW,CTIB1,WLDL,WLDT,CTUMT,KTUB
     1E,KFIN,NFPIN,DDIB,WTIB,DLIB,CTUB1,CTUBE,CTUBA,CTUBW,CTBUN,CTIB,WLD
     2IB,SLABT,SMATT,SUPPM,SUPPL,SUPP,DTO,DLTTK,DFH,DFT,WTUBF,CTUB,CFIN)
C
C
C --- NOZZLE COST ---
C
C     CALCULATE THE COST FOR INSTALLING AN INLET NOZZLE ON FRONT HEADER
      CALL NOZZLE(DTN1I,CTNZI1)
C
C     CALCULATE THE COST FOR INSTALLING AN OUTLET NOZZLE ON FRONT HEADER
      CALL NOZZLE(DTN1O,CTNZO1)
C
C     CALCULATE THE COST FOR INSTALLING AN OUTLET NOZZLE ON BACK HEADER
      CALL NOZZLE(DTN2O,CTNZO2)
C
C     TOTAL COST FOR THE NOZZLES
      CTNOZ=Z001I*CTNZI1+Z001O*CTNZO1+Z002O*CTNZO2
      CTNOZ=CTNOZ*ZBUP
C
C
C
C --- CALCULATE THE COST OF PLENUM
      CALL PLENUM(NFAN,DFAN,DL,DHEDW,TSPLM,DENCS,CPLM1,CPLL1,CTPLM,PLMTL
     1,PLLAB,ZBUP)
C
C --- CALCULATE FANS COST
      CALL FAN(NFAN,DFAN,NBLD,IDFAN,CFAN1,CTFAN)
C
C --- CALCULATE MOTORS COST
C *** SPECIFY MOTORS IN 25 HP INCREMENTS
      XI=HPMOT/25.
      I=XI
      I=I*25+25
      HPMSP=I
      CALL MOTOR(NMOT,MORPM,HPMSP,CMOT1,CTMOT)
C
C --- CALCULATE TRANSMISSION COST
      CALL TRANS(NMOT,HPMSP,CTRAN,TRANC)
C
C --- CALCULATE ERECTION COST
      CALL EXSTP(ZBUP,NBLD,NFAN,ZBPU,CERCT)
C
      CTACS=CTPLM+CTFAN+CTMOT+TRANC+CTNOZ
      CTACO=CTACS*ZBPU
C --- CALCULATE STRUCTURE COST
C     ASSUME STEEL INDEX IS U.S. AVERAGE AND ROOF LIVE LOAD OF 40 LB/FT2
      DATA STLAD,RLL/0.,40./
      TUBWT=WTUBF
      CALL STRUCT(NTT,TUBWT,DL,DHEDW,RLL,DHSTR,STLAD,ZBUP,ZBPU,CTSTR)
C
C
C --- SHIPPING COST IS 2.50 $/CWT BELOW 60 FEET AND 5.00 $/CWT ABOVE 60
C --- ASSUME MODULES WEIGH 1.4 TIMES THE TUBE WEIGHT AS IN STRUCT
      WSHIP=WTUBF*DL*ZTT*ZBUP*ZBPU*1.4
      CSHIP=WSHIP*.025
      IF(DL.GT.60.)CSHIP=WSHIP*.05
C
C
C
C
C --- TOTAL LABOR COST ---
      CTLAB=SLABF+SLABB+SLABT
      CTLAB=CTLAB*ZBUP*ZBPU+PLLAB*ZBPU
C
C --- TOTAL MATERIAL COST ---
      CTMAT=SMATF+SMATB+SMATT
      CTMAT=CTMAT*ZBUP*ZBPU+PLMTL*ZBPU
```

```
C
C
C *** MINIMUM COST IS
      CTACP=CTACO-ZBPU*CTPLM
C
C === TOTAL BASE COST FOR THE AIR COOLER ($) ===
      CTOT=GAFAC*(CTMAT*ESCAL+CTLAB*OVHDL+CTACP)
C
C
C === TOTAL FIRM PRICE FOR THE AIR COOLER ($) ===
C *** CALCULATE PROFIT FACTOR AS FUNCTION OF TOTAL COST
      IF(CTOT-725.E06)4,4,2
    4 FPROF=1.4-.044*ALOG10(CTOT)
      GO TO 6
    2 FPROF=1.01
    6 CONTINUE
      CTTOT=CTOT*FPROF
C
      CSTOR=CTTOT
      CTTOT=CTTOT+CERCT+CTSTR+CSHIP
      IF(KNTR1.EQ.0)GO TO 300
C
C --- PRINT OUT FINAL RESULTS ---
C
C
      WRITE(6,10)
   10 FORMAT(1H1,55X,15HAIR COOLER COST)
C
C
C
      NTRAN=NMOT
      NBUP=ZBUP+.01
      NBUNT=NBUP*NBPU
  403 DO 430 I=1,7
  430 ERT(I)=ERT3(I)
  404 CONTINUE
C
C
      IF (HPMOT.GT.7.5) GO TO 445
      DO 441 I=1,3
  441 TRATY(I)=TRATY1(I)
      GO TO 452
C
  445 CONTINUE
      IF (HPMOT.GT.20.0) GO TO 449
      DO 446 I=1,3
  446 TRATY(I)=TRATY2(I)
      GO TO 452
C
  449 DO 450 I=1,3
  450 TRATY(I)=TRATY3(I)                                                    02420
  452 CONTINUE                                                              02430
C                                                                           02440
      GO TO (432,434,436), IDFAN                                            02450
  432 DO 433 I=1,2                                                          02460
  433 FANTY(I)=FANTY1(I)                                                    02470
      GO TO 438                                                             02480
  434 DO 435 I=1,2                                                          02490
  435 FANTY(I)=FANTY2(I)                                                    02500
      GO TO 438                                                             02510
  436 DO 437 I=1,2                                                          02520
  437 FANTY(I)=FANTY3(I)                                                    02530
  438 CONTINUE                                                              02540
   55 CONTINUE                                                              02550
      CC=CSTOR+CERCT+CSHIP+CTSTR                                            02560
      WRITE(6,57)CC                                                         02570
   57 FORMAT(1H0,29HTOTAL INSTALLED COST PER UNIT,23X,F12.2,2H $)           02580
   68 CONTINUE                                                              02590
C                                                                           02600
C                                                                           02610
C --- PRINT OUT DESIGN INFORMATION ---                                      02620
C                                                                           02630
   63 WRITE(6,66)                                                           02640
   66 FORMAT(/,2X,132(1H-),/)                                               02650
   69 CONTINUE                                                              02660
      WRITE(6,60)                                                           02670
   60 FORMAT(48X,31HHEAT EXCHANGER DESIGN VARIABLES,/)                      02680
      WRITE(6,62) (CASE(I), I=1,3), (ERT(I), I=1,7)                         02690
   62 FORMAT(1H ,2X,7HCASE ID,18X,3A4,31X,7A4)                              02700
      WRITE(6,64) NBPU,NBUNT                                                02710
   64 FORMAT(1H ,2X,23HNO. OF BAYS IN PARALLEL,11X,I3,31X,34HNO. OF BUND    02720
     1LE SECTIONS IN PARALLEL,I5)                                           02730
      WRITE(6,70)                                                           02740
   70 FORMAT(1H ,1X,132(1H-))                                               02750
      WRITE(6,75)                                                           02760
   75 FORMAT(1H ,2X,*TUBE BUNDLE INFORMATION*,/)                            02770
      WRITE(6,80) DL,DSL                                                    02780
   80 FORMAT(1H ,7X,*BUNDLE LENGTH (FT)*,5X,F12.2,28X,*LONGITUDINAL PITC    02790
     1H*,4X,*(INCH)*,2X,F14.4)                                              02800
      WRITE(6,85) NTT,DST                                                   02810
   85 FORMAT(1H ,7X,*TOTAL NUMBER OF TUBES  *,I9,31X,*TRANSVERSE   PITCH    02820
     1    (INCH)   *,F14.4)                                                 02830
      WRITE(6,90) NTR,DTI                                                   02840
   90 FORMAT(1H ,7X,*NUMBER OF TUBE ROWS    *,I9,31X,*TUBE INSIDE  DIAME    02850
     1TER (INCH)   *,F12.2)                                                 02860
      WRITE(6,91) NTP,DTO                                                   02870
   91 FORMAT(1H ,7X,*NUMBER OF TUBE PASSES  *,I9,31X,*TUBE OUTSIDE DIAME    02880
     1TER (INCH)   *,F12.2,/)                                               02890
      IF (KTUBE) 92,92,94                                                   02900
   92 WRITE(6,93)DFH                                                        02910
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 93 FORMAT(1H ,7X,9HTUBE TYPE,11X,17HROUND WELDED C.S.,26X,10HFIN HEIG
   1HT,12X,
   16H(INCH),9X,F7.4)
    GO TO 96
 94 WRITE(6,95)DFH
 95 FORMAT(8X,9HTUBE TYPE,9X,19HROUND SEAMLESS C.S.,26X,10HFIN HEIGHT,
   112X,
   16H(INCH),9X,F7.4)
 96 CONTINUE
    IF (KFIN) 97,97,99
 97 WRITE(6,98)DFT
 98 FORMAT(8X,9HFIN  TYPE,9X,14HALUMINUM L FIN,31X,
   113HFIN THICKNESS,9X,
   16H(INCH),9X,F7.4)
    GO TO 101
 99 WRITE(6,100)DFT
100 FORMAT(8X,9HFIN  TYPE,9X,14HALUMINUM G FIN,31X,
   113HFIN THICKNESS,9X,
   16H(INCH),9X,F7.4)
101 CONTINUE
    ZFPIN=NFPIN
    WRITE(6,102)ZFPIN,WTUBF
102 FORMAT(1H ,7X,20HNO. OF FINS PER INCH,8X,F4.1,31X,30HWEIGHT OF FIN
   1 AND TUBE (LB/FT),7X,F6.3)
    WRITE(6,70)
226 CONTINUE
    WRITE(6,230)
230 FORMAT(1H ,2X,20HMECHANICAL EQUIPMENT)
    WRITE(6,232)(FANTY(I),I=1,2),MORPM,(TRATY(I),I=1,2)
232 FORMAT(4X,9HFAN TYPE.,14X,2A4,8X,11HMOTOR TYPE.,5X,3HA/C,I6,
   14H RPM,6X,18HTRANSMISSION TYPE.,6X,3A4)
    WRITE(6,236) NFAN,NMOT,NTRAN
236 FORMAT(1H ,7X,8HNO./BAY.,13X,I2,18X,8HNO./BAY.,13X,I2,19X,8HNO./BA
   1Y.,13X,I2)
    WRITE(6,238) DFAN,HPMOT
238 FORMAT(8X,13HDIAMETER (FT),7X,F6.2,12X,11HPOWER/MOTOR,
   112H -OPERATING ,F6.2)
    WRITE(6,240)NBLD,HPMSP
240 FORMAT(8X,13HNO.BLADES/FAN,8X,I2,26X,12H -INSTALLED ,F6.2)
    WRITE(6,70)
    WRITE(6,242) DHSTR
242 FORMAT(1H ,2X,21HSTRUCTURE HEIGHT (FT),13X,F6.2)
    WRITE(6,70)
300 RETURN
    END
```

```
      SUBROUTINE BOX
      COMMON/EPA/TNMIN,TNMAX,TSAT(21),COSTT(21),X(10,21),XC(10),VAMAX,
     1VAMIN,VWMAX,VWMIN,XN,XP,SUBCL,QMIN,QMAX,PITCH,DIA,
     2RNGMX,RNGMN,TLMIN,TLMAX,TITDX,TITDN,TSATA,TSATZ,XHEAT(21)
      COMMON IDUM,KGO,IDUM1(4),DUMP(3),IDUMW(34),DUMW(58),
     1DTIM,DUME1(4),PT,DUMM(107),FALT,DUME2(74),ZTRD,ANGI,DUME3,
     2ZBUP,DUME4(4),ZNFI,PTI,DUME7(5),TAMB,HALT,C319,DUME9(4),RFD,
     3DUME10(18),CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),DUME11,
     4ZTPD,DUME12,COST(7),DUME14(912)
      COMMON/PEN/ATTR(20),DATTR(20),AMBTPT(20),BCAPC,NATTR,CAPCST,CMAIN,
     1MACC,AFCR2,XLVL,FLCST,CAPBS,PLDFT(20),STMCT,CUTMP,SHELP,BHTRT(6)
      COMMON/STIN/XLDFT(6),BP(28),HTRTD(28,6),HTRJD(28,6),NLODS,NBKPR
     1,PLOAD,BPMNM(6),TPMNM(6)
      COMMON/JUMP/JAKE,TINMX,NOO2I,DTN2I,NOO1I,NFPIN,NOO2O,NOO1O
      COMMON/JAN7/WBMAX,PBPMN,TBPMN,CPEFF,WTEFF,PBPHT,EBPOM,PPOM,CWRTI,
     1SCPMP,CCPMP,FDMAX,MXFBL,SPRNZ,SPRHT,CWTLV,DPPCT,PDMAX,CONCT
      COMMON/PIPE/XDIA(20),XLGT(20),NN1,NN2,XTOWR,PLNMH,TTTBH,VX,VN
     1,VAVE
      COMMON/BCKPR/BCKMN,BCKMX
      COMMON/FAST/STOW(3)
      COMMON/SCOND/TTDMN,TTDMX,TISUM(21)
      COMMON/CASED/BARB(13)
      READ(5,7)KNO,(BARB(I),I=1,13)
C *** READ CARD LEFT FROM ORIGINAL AC INPUT
      READ(5,3)KNO,ANGI,ZBUP,ZNFI,PTI,HALT,COST(2),COST(6),ZTRD,ZTPD
      ZNOZ(1)=2.
      ZNOZ(2)=2.
      NP=ZTPD+0.01
      NTR=ZTRD+0.01
      CALL INPUT
C
C     SET VARIABLES
C
      STOW(1)=0.
      STOW(2)=0.
      STOW(3)=0.
      N=6
      JAKE=1
      CALL EXINI
      IF(KGO-1)2,2,300
    2 CALL GEOM1
      PITCH=PT
      DIA=DTIM
C *** CALC FALT - CORRECTION TO AIR DENSITY
      IF(HALT-4000.0)4,4,6
    4 FALT=1.-3.4E-5*HALT
      GO TO 9
    6 FALT=.985-3.025E-5*HALT
    9 CONTINUE
C
```

```
C     READ INPUT
C
  100 READ(5,150)KNO,TLMAX,TITDN,TOL,ALF,DELT,ITRMX,NITR,BCAPC,
     1NATTR,CAPCST,TTDMN,TTDMX
      READ(5,225)KNO,AFCR2,FLCST,TNMAX,TNMIN,(BHTRT(I),I=1,6)
      READ(5,230)KNO,VAMAX,VAMIN,VWMAX,VWMIN,RNGMX,RNGMN,TITDX,TLMIN,
     1VX,VN,CONCT,STMCT,CUTMP,SHELP
C *** DETERMINE AVERAGE DESIGN VELOCITY FOR PIPING
      VAVE=.5*(VX+VN)
      READ(5,240)KNO,WBMAX,PDMAX,MXFBL,FDMAX,DPPCT,CWTLV,SPRHT,SPRNZ,
     1SCPMP,PBPHT,CPEFF,WTEFF,CWRTI,EBPOM
      DO 110 M=1,4
      MM=1+(M-1)*5
      MMM=MM+4
  110 READ(5,250)KNO,((ATTR(I),DATTR(I),PLDFT(I)),I=MM,MMM)
      READ(5,325)KNO,NBKPR,NLODS,((XLDFT(I),BPMNM(I)),I=1,6),(BP(I),I=1,
     19)
      READ(5,350)KNO,(BP(I),I=10,28)
      J=1
  112 LSRT=1
  114 LEFT=NBKPR-LSRT+1
      IF(LEFT)116,116,118
  116 J=J+1
      IF(J-NLODS)112,112,124
  118 J1=J
      I1ST=LSRT
      IF(LEFT-8)122,120,120
  120 I1END=LSRT+7
      LSRT=LSRT+8
  121 READ(5,375)KNO,((HTRTD(I,J1),HTRJD(I,J1)),I=I1ST,I1END)
      GO TO 114
  122 I1END=NBKPR
      IF((J+1)-NLODS)126,126,123
  123 LSRT=NBKPR+1
      GO TO 121
  126 J2=J+1
      I2ST=1
      MADD=8-LEFT
      IF(MADD-NBKPR)128,130,130
  128 I2END=MADD
      J=J2
      LSRT=MADD+1
      GO TO 132
  130 I2END=NBKPR
      IF((J+2)-NLODS)135,135,131
  131 LSRT=NBKPR+1
      J=J2
  132 READ(5,375)KNO,((HTRTD(I,J1),HTRJD(I,J1)),I=I1ST,I1END),
     1                 ((HTRTD(I,J2),HTRJD(I,J2)),I=I2ST,I2END)
      GO TO 114
  135 J3=J+2
      I3ST=1
      I3END=MADD-NBKPR
      J=J3
      LSRT=I3END+1
      READ(5,375)KNO,((HTRTD(I,J1),HTRJD(I,J1)),I=I1ST,I1END),
     1               ((HTRTD(I,J2),HTRJD(I,J2)),I=I2ST,I2END),
     2               ((HTRTD(I,J3),HTRJD(I,J3)),I=I3ST,I3END)
      GO TO 114
  124 CONTINUE
      WRITE(6,199)ANGI,ZBUP,ZNFI,PTI,HALT,COST(2),COST(6)
  125 WRITE(6,200)TLMAX,TITDN,TOL,ALF,DELT,ITRMX,NITR,NP,NTR,BCAPC,
     1NATTR,CAPCST
      WRITE(6,175)AFCR2,FLCST,TNMAX,TNMIN,TTDMN,TTDMX
      WRITE(6,190)VAMAX,VAMIN,VWMAX,VWMIN,RNGMX,RNGMN,TITDX,TLMIN
     1,VX,VN,CONCT,STMCT,CUTMP,SHELP
      WRITE(6,195)WBMAX,PDMAX,MXFBL,FDMAX,DPPCT,CWTLV,SPRHT,SPRNZ,SCPMP,
     1PBPHT,CPEFF,WTEFF,CWRTI,EBPOM
      Q11=0.
      Q1=0.
      CMAIN=0.
      WRITE(6,270)
      DO 140 I=1,NATTR
      WRITE(6,275)ATTR(I),PLDFT(I),DATTR(I)
      Q1=Q1+DATTR(I)
      Q11=Q11+DATTR(I)*PLDFT(I)
C *** FIND APPROX. AVERAGE WEIGHTED ANNUAL POWER COST IN MILLS/KW
      IF(PLDFT(I)-.999)139,136,136
  136 IF(ATTR(I)-CUTMP)137,137,138
  137 CMAIN=CMAIN+DATTR(I)*SHELP
      GO TO 140
  138 CMAIN=CMAIN+DATTR(I)*COST(6)
      GO TO 140
C *** ASSUME A HEAT RATE OF 9000 AT PART LOAD
  139 CMAIN=CMAIN+DATTR(I)*FLCST*9.
  140 CONTINUE
      Q11=Q11/8760.
      WRITE(6,276)Q1,Q11
      WRITE(6,400)NLODS,NLODS,(XLDFT(I),I=1,NLODS),(XLDFT(I),I=1,NLODS)
      WRITE(6,425)
      DO 500 I=1,NBKPR
      WRITE(6,450)BP(I),(HTRTD(I,J),J=1,NLODS),(HTRJD(I,J),J=1,NLODS)
  500 CONTINUE
      WRITE(6,475)(BPMNM(I),I=1,NLODS)
      WRITE(6,480)(BHTRT(I),I=1,NLODS)
C *** CONVERT HEAT REJECT TO INTERNAL  AND  FIND QMIN AND QMAX
      K=0
      BCKMN=50.
      DO 40 I=1,NLODS
      IF(BPMNM(I).LT.BCKMN)BCKMN=BPMNM(I)
      TPMNM(I)=TSL(BPMNM(I))                                            04870
      IF(XLDFT(I)-.9999)25,20,20                                        04880
   20 K=I                                                               04890
   25 DO 40 J=1,NBKPR                                                   04900
      HTRJD(J,I)=HTRJD(J,I)*1.E+06                                      04910
   40 CONTINUE                                                          04920
      IF(K.EQ.0)WRITE(6,105)                                            04930
      IF(HTRJD(1,K)-HTRJD(NBKPR,K))50,50,60                             04940
   50 CONTINUE                                                          04950
      QMAX=HTRJD(NBKPR,K)                                               04960
      BCKMX=BP(NBKPR)                                                   04970
      TINMX=TSL(BP(NBKPR))                                              04980
      GO TO 70                                                          04990
   60 CONTINUE                                                          05000
      QMAX=HTRJD(1,K)                                                   05010
      BCKMX=BP(1)                                                       05020
      TINMX=TSL(BP(1))                                                  05030
   70 CONTINUE                                                          05040
      ICOUNT=0                                                          05050
      PMAX=1.                                                           05060
      PMIN=.05                                                          05070
      XN=NTR                                                            05080
      XP=NP                                                             05090
      XA1=VAMAX*PITCH*5./XN                                             05100
      XA2=VAMIN*PITCH*5./XN                                             05110
      XW1=VWMAX*19.635*DIA**2/XP                                        05120
      XW2=VWMIN*19.635*DIA**2/XP                                        05130
C *** MIN. DESIGN Q IS WHEN FAN CONTROL NORMALLY WOULD START             05140
      CALL QTURB(QMIN,TPMNM(K),XLDFT(K),2)                              05150
   85 ICOUNT=ICOUNT+1                                                   05160
C *** LOWEST POSSIBLE INLET AND OUTLET WATER TEMPERATURES               05170
      Q1=QMIN*1.000001                                                  05180
      CALL QTURB(Q1,TLIW,1.,1)                                          05190
      TLIW=TLIW-TTDMX+459.67                                            05200
      TLOW=AMAX1(32.+459.67,TLIW-RNGMX)                                 05210
C *** HIGHEST POSSIBLE INLET AND OUTLET WATER TEMPERATURES              05220
      Q1=QMAX*.999999                                                   05230
      CALL QTURB(Q1,THIW,1.,1)                                          05240
      THIW=THIW-TTDMN+459.67                                            05250
      THOW=THIW-RNGMN                                                   05260
C *** LOWEST AND HIGHEST POSSIBLE INLET AIR TEMPERATURES                05270
      TLIA=AMAX1(409.67,TLIW-TITDX)                                     05280
      THIA=THIW-TITDN                                                   05290
C *** PHYSICAL PROPERTIES AT LOWEST AVERAGE WATER TEMPERATURE           05300
      TAV=.5*(TLIW+TLOW)                                                05310
      TAV=TAV-459.67                                                    05320
      CALL PPAUT1(TAV,CPLW,DENW,D1,D3,KODE)                             05330
C *** PHYSICAL PROPERTIES AT HIGHEST AVERAGE WATER TEMPERATURE          05340
      TAV=.5*(THIW+THOW)                                                05350
      TAV=TAV-459.67                                                    05360
      CALL PPAUT1(TAV,CPW,DENLW,D1,D3,KODE)                             05370
C *** PHYSICAL PROPERTIES AT LOWEST INLET AIR TEMPERATURE                05380
      CALL PPROP(TLIA,14.7,2,DENA,D3,CPLA,D4,D5,0,2)                    05390
C *** PHYSICAL PROPERTIES AT HIGHEST INLET AIR TEMPERATURE               05400
      CALL PPROP(THIA,14.7,2,DENLA,D3,CPA,D4,D5,0,2)                    05410
      TT=THIW-459.67                                                    05420
      TTT=TT-32.                                                        05430
C *** TEMPORARILY DO NOT ALLOW AN ITD DESIGN THAT WILL CAUSE BACK        05440
C *** PRESSURE TO EXCEED MAXIMUM AT HOTTEST AMBIENT.  EVENTUALLY THE     05450
C *** PROGRAM MUST RECOGNIZE THIS CONDITION AND REDUCE TURBINE LOAD.    05460
      TITDX=AMIN1(TT+50.,TITDX,(TINMX-TTDMX-ATTR(1)-3.))                05470
      RNGMX=AMIN1(TTT,RNGMX)                                            05480
C                                                                       05490
C *** TIGHTEN UP CONSTRAINTS IF POSSIBLE                                05500
C                                                                       05510
      TNMIN1=QMIN/RNGMX/DENW/XW1/CPW                                    05520
      TNMIN=AMAX1(TNMIN,TNMIN1)                                         05530
      TNMAX1=QMAX/RNGMN/DENLW/XW2/CPLW                                  05540
      TNMAX=AMIN1(TNMAX,TNMAX1)                                         05550
      RNGMX2=TNMAX1*RNGMN/TNMIN                                         05560
      RNGMN2=TNMIN1*RNGMX/TNMAX                                         05570
      RNGMX=AMIN1(RNGMX,RNGMX2)                                         05580
      RNGMN=AMAX1(RNGMN,RNGMN2)                                         05590
      QMAX4=CPW*RNGMX*XW1*DENW*TNMAX                                    05600
      QMIN4=CPLW*RNGMN*XW2*DENLW*TNMIN                                  05610
      QMAX=AMIN1(QMAX,QMAX4)                                            05620
      QMIN=AMAX1(QMIN,QMIN4)                                            05630
      PMAX1=QMAX/CPLA/TITDN/XA2/DENLA/TLMIN/TNMIN                       05640
      PMIN1=QMIN/CPA/TITDX/XA1/DENA/TLMAX/TNMAX                         05650
      PMAX=AMIN1(PMAX1,PMAX)                                            05660
      PMIN=AMAX1(PMIN1,PMIN)                                            05670
      TITDX2=PMAX1*TITDN/PMIN                                           05680
      TITDN2=PMIN1*TITDX/PMAX                                           05690
      TITDX=AMIN1(TITDX,TITDX2)                                         05700
      TITDN=AMAX1(TITDN,TITDN2)                                         05710
      PITDMN=TITDN2*PMAX                                                05720
      PITDMX=TITDX2*PMIN                                                05730
      PITDN2=PMIN*TITDN                                                 05740
      PITDX2=PMAX*TITDX                                                 05750
      PITDMN=AMAX1(PITDMN,PITDN2)                                       05760
      PITDMX=AMIN1(PITDMX,PITDX2)                                       05770
      TLMAX2=QMAX/CPLA/XA2/PITDMN/DENLA/TNMIN                           05780
      TLMIN2=QMIN/CPA/XA1/PITDMX/DENA/TNMAX                             05790
      TLMIN=AMAX1(TLMIN,TLMIN2)                                         05800
      TLMAX=AMIN1(TLMAX,TLMAX2)                                         05810
      TNMIN2=TLMIN2*TNMAX/TLMAX                                         05820
      TNMAX2=TLMAX2*TNMIN/TLMIN                                         05830
      TNMIN=AMAX1(TNMIN,TNMIN2)                                         05840
      TNMAX=AMIN1(TNMAX,TNMAX2)                                         05850
      RNGMX3=CPA*PITDMX    *XA1*DENA*TLMAX/CPLW/XW2/DENLW               05860
      RNGMN3=CPLA*PITDMN     *XA2*DENLA*TLMIN/CPW/XW1/DENW
      RNGMN=AMAX1(RNGMN,RNGMN3)
      RNGMX=AMIN1(RNGMX,RNGMX3)
      PMAX2=RNGMX/RNGMN3*PITDMN/TITDN
      PMIN2=RNGMN/RNGMX3*PITDMX/TITDX
      PMIN=AMAX1(PMIN,PMIN2)
      PMAX=AMIN1(PMAX,PMAX2)
      TITDX3=PMAX2*TITDN/PMIN
      TITDN3=PMIN2*TITDX/PMAX
      TITDX=AMIN1(TITDX,TITDX3)
      TITDN=AMAX1(TITDN,TITDN3)
      PITDN3=PMIN*TITDN
      PITDX3=PMAX*TITDX
      PITDMN=AMAX1(PITDMN,PITDN3)
      PITDMX=AMIN1(PITDMX,PITDX3)
      TLMIN3=CPLW*RNGMN*XW2*DENLW/CPA/PITDMX/XA1/DENA
      TLMAX3=CPW*RNGMX*XW1*DENW/CPLA/PITDMN/XA2/DENLA
      TLMIN=AMAX1(TLMIN,TLMIN3)
      TLMAX=AMIN1(TLMAX,TLMAX3)
      QMAX5=CPA*PITDMX     *XA1*DENA*TLMAX*TNMAX
      QMIN5=CPLA*PITDMN    *XA2*DENLA*TLMIN*TNMIN
      QMAX=AMIN1(QMAX,QMAX5)
      QMIN=AMAX1(QMIN,QMIN5)
C
C *** CHECK FOR INCONSISTANCIES IN CONSTRAINTS
C
      IF(PMIN.GT.(PMAX+.01))GO TO 322
      IF(RNGMN.GT.(RNGMX+1.))GO TO 305
      IF(TITDN.GT.(TITDX+1.))GO TO 310
      IF(TLMIN.GT.(TLMAX+.3))GO TO 315
C
      IF(TNMIN.GT.(1.005*TNMAX))GO TO 320
C
C *** SEE IF QMIN AND QMAX CAN BE FURTHER CONSTRAINED
      ZRN=32.+TTDMN+RNGMN
      CALL QTURB(QMIN3,ZRN,1.,2)
      QMIN=AMAX1(QMIN,QMIN3)
C *** RUN THROUGH CONSTRAINTS ONCE MORE
      IF(ICOUNT.EQ.1)GO TO 85
C *** SET MIN AND MAX SATURATION TEMPERATURES
      Q1=QMIN*1.000001
      CALL QTURB(Q1,TSATA,1.,1)
      Q1=QMAX*.999999
      CALL QTURB(Q1,TSATZ,1.,1)
      IF(QMIN.GT.(1.001*QMAX))GO TO 321
C
C     CALL SUBROUTINE TO PERFORM BOX OPTIMIZATION
C
      CALL MJBOX(TOL,ALF,DELT,ITRMX,NITR,N)
C
```

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105 FORMAT(///,33H CAUTION. NO LOAD OF 1. WAS INPUT)
  3 FORMAT(I2,F5.0,F2.0,2F5.0,F6.0,2F4.0,F3.0,F4.0)
  7 FORMAT(I2,13A5)
150 FORMAT(I2,F6.2,F5.2,F4.2,2F4.2,2I3,F6.1,I2,F5.1,2F4.1)
175 FORMAT(9X,42HAFCR2  FLCST   TNMAX    TNMIN  TTDMN TTDMX,/,6X,
   12F7.2,1X,2F9.0,2F6.1,/)
190 FORMAT(9X,48HVAMAX VAMIN  VWMAX VWMIN RNGMX RNGMN TITDX TLMIN,
   138H   VX    VN   CONCT  STMCT CUTMP SHELP,/,8X,2F6.1,1X,8F6.1,
   22F7.2,F6.1,F6.2,/)
195 FORMAT(9X,49HWBMAX PDMAX  MXFBL FDMAX DPPCT CWTLV SPRHT SPRNZ ,
   137HSCPMP PBPHT  CPEFF  WTEFF CWRTI EBPOM,/,8X,F6.2,F6.1,I5,F8.1,
   2F6.0,2F6.1,F6.2,2F6.1,2F7.3,F6.1,F6.3,//)
199 FORMAT(1H1,1X,38HINPUT: ANGI   ZBUP   ZNFI  PTI   HALT ,
   111HCOST2 COST6,/,7X,F6.1,F7.0,F7.1,F4.1,F7.0,F6.2,F6.1,/)
200 FORMAT(9X,37HTLMAX  TITDN  TOL   ALF   DELT  ITRMX,
   133H NITR NP NTR BCAPC  NATTR  CAPCST,/,7X,2F7.2,F6.3,F5.1,F7.3,
   2I6,I5,I4,I3,F7.0,I5,F10.1,/)
225 FORMAT(I2,F3.1,F4.2,8F7.0)
230 FORMAT(I2,2F5.1,2F4.1,3F5.1,3F4.1,F4.2,F6.3,F5.1,F5.2)
240 FORMAT(I2,F5.2,F5.1,I2,F4.1,F5.0,2F4.1,F5.2,F6.0,F4.1,2F3.1,F5.1,
   1F4.1)
250 FORMAT(I2,5(F5.1,F6.1,F4.2))
270 FORMAT(1X,26HTEMPERATURE - LOAD PROFILE,/,1X,26(1H-),/,
   120H   TEMP  LOAD  HOURS)
275 FORMAT(1X,F6.1,F6.2,F7.0)
276 FORMAT(15X,5H-----,/,14X,F6.0,12H TOTAL HOURS,//,14X,F6.3,
   112H LOAD FACTOR)
325 FORMAT(2I2,I1,12F3.2,9F4.0)
350 FORMAT(I2,19F4.0)
375 FORMAT(I2,8(F5.0,F4.0))
400 FORMAT(1H1,42X,11(1H*),27H STEAM TURBINE INFORMATION ,11(1H*),//,
   113H **THE FIRST ,I1,22H COLUMNS ARE HEAT RATE,/,13H ***THE LAST ,
   2I1,24H COLUMNS ARE HEAT REJECT,/,7H -LOAD-,/,5X,18F7.2)
425 FORMAT(/,4H  BP,/,4H  --)
450 FORMAT(1X,F4.1,18F7.0)
475 FORMAT(/,37H MINIMUM BACK PRESSURE AT ABOVE LOADS,/,5X,9F7.2)
480 FORMAT(/,40H COMPARATIVE HEAT RATE AT ABOVE LOADS TO,/,
   132H DETERMINE INCREMENTAL FUEL COST,/,5X,6F7.0)
300 CONTINUE
    GO TO 600
305 WRITE(6,306)RNGMN,RNGMX
306 FORMAT(///,8H RNGMN= ,E12.5,8H RNGMX= ,E12.5)
    GO TO 322
310 WRITE(6,311)TITDN,TITDX
311 FORMAT(///,8H TITDN= ,E12.5,8H TITDX= ,E12.5)
    GO TO 322
315 WRITE(6,316)TLMIN,TLMAX
316 FORMAT(///,8H TLMIN= ,E12.5,8H TLMAX= ,E12.5)
    GO TO 322
319 FORMAT(///,8H TNMIN= ,E12.5,8H TNMAX= ,E12.5)
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320 WRITE(6,319)TNMIN,TNMAX
    GO TO 322
321 WRITE(6,323)QMIN,QMAX
322 WRITE(6,312)
323 FORMAT(///,8H  QMIN= ,E12.5,8H  QMAX= ,E12.5)
312 FORMAT(///,45H BOX CANNOT PROCEED. CASE IS OVER CONSTRAINED)
600 TAMB=0.0
    RETURN
    END

      SUBROUTINE BUNDLE(ZTT,DL,DHOF,DDOF,DDOB,DHEDW,CTIB1,WLDL,WLDT,CTUM
     1T,KTUBE,KFIN,NFPIN,DDIB,WTIB,DLIB,CTUB1,CTUBE,CTUBA,CTUBW,CTBUN,CT
     2IB,WLDIB,SLABT,SMATT,SUPPM,SUPPL,SUPP,DTO,DLTTK,DFH,DFT,WTUBF,CTUB
     3,CFIN)
C
C *** INPUT VARIABLES ***
C
C     ZTT   = NTT, TOTAL NUMBER OF TUBES
C     DL    = TUBE BUNDLE LENGTH (FT)
C     DHOF  = OUTSIDE HEIGHT OF FRONT HEADER (INCH)
C     DDOF  = OUTSIDE DEPTH OF FRONT HEADER (INCH)
C     DDOB  = OUTSIDE DEPTH OF BACK HEADER (INCH)
C     DHEDW = BUNDLE WIDTH (INCH)
C     CTIB1 = UNIT COST FOR I-BEAM ($/LB)
C     WLDL  =WELDING LABOR COST ($/HR)
C     WLDT  = WELDING SPEED (MIN/INCH)
C     CTUMT = TUBE ASSEMBLING LABOR COST ($/HR)
C     KTUBE = 0 FOR WELDED TUBE,    1 FOR SEAMLESS TUBE
C     KFIN  = 0 FOR L FIN,    1 FOR G FIN
C     NFPIN = NUMBER OF FINS PER INCH
C
C *** OUTPUT VARIABLES ***
C
C     DDIB  = I-BEAM DEPTH (INCH)
C     WTIB  = UNIT WEIGHT OF I-BEAM (LB/FT)
C     DLIB  = LENGTH OF I-BEAM (FT)
C     CTUB1 = UNIT TUBE COST ($/FT)
C     CTBUN = TOTAL COST FOR THE TUBE BUNDLE SECTION ($)
C     SUPP  = COST FOR SUPPORTS ($)
C     SLABT = TOTAL LABOR COST FOR THE BUNDLE ($)
C     SMATT = TOTAL MATERIAL COST FOR THE BUNDLE ($)
C
```

```
C
C     COST OF TUBE MATERIAL
C *** CALL TUBEF TO CALCULATE COST OF ANY TYPE OF BARE OR FINNED TUBES
C *** (DATA AS OF APRIL,1976)
      CALL TUBEF(KTUBE,KFIN,NFPIN,DTO,DLTTK,DFH,DFT,WTUBE,WFIN,WTUBF,
     1ATUBE,BFIN,CTUB1,CTUB,CFIN)
      CTUBE=ZTT*DL*CTUB1
C
C     ASSEMBLING COST ($)
C
C     BUNDLE ASSEMBLING REQUIRES TWO MAN, 15 MINUTES TO MOUNT ONE TUBE
C     ONTO THE TUBE SHEETS
C     CTUMT=3.0 $/HR
C     ASSEMBLING COST IS PROPORTIONAL TO BUNDLE LENGTH
C     ASSUME  1.0 HR FOR 80 FT,  0.5 HR FOR 40 FT TUBE LENGTH
C
      CTUBA=2.0*ZTT*(0.75*DL)/60.0*CTUMT
C
C     BUNDLE WELDING REQUIRES ONE MAN 15 MINUTES TO WELD ONE TUBE
C     END ONTO A HOLE
      CTUBW=2.0*ZTT*15.0/60.0*WLDL
C
      CTBUN=CTUBE+CTUBA+CTUBW
C
C
C
C     THERE ARE TWO I-BEAMS TO SUPPORT THE BUNDLES
      DHO=DHOF
C
      IF (DHO-AINT(DHO)) 60,60,70
C
   60 CONTINUE
      DDIB=AINT(DHO)
      GO TO 80
C
   70 CONTINUE
      DDIB=AINT(DHO)+1.0
C
   80 CONTINUE
C
C     USE THE SPECIFICATIONS OF (( AMERICAN STANDARD CHANNELS ))
C     HERE CONFINE THE DEPTH OF I-BEAM IN THE RANGE OF 9 TO 18 FT
C
C     WTIB  = UNIT WEIGHT OF I-BEAM (LB/FT)
C
      IF(DDIB-8.)82,82,84
   82 CONTINUE
      WTIB=1.567*(DDIB-3.)+4.
      GO TO 200
   84 CONTINUE
```

```
      IF (DDIB-9.0) 90,90,100
   90 CONTINUE
      WTIB=13.4
      GO TO 200
  100 CONTINUE
      IF (DDIB-10.0) 110,110,120
  110 CONTINUE
      WTIB=15.3
      GO TO 200
  120 CONTINUE
      IF (DDIB-12.0) 130,130,140
  130 CONTINUE
      WTIB=20.7
      GO TO 200
  140 CONTINUE
      IF (DDIB-15.0) 150,150,160
  150 CONTINUE
      WTIB=33.9
      GO TO 200
  160 CONTINUE
      IF (DDIB-18.0) 170,170,180
  170 CONTINUE
      WTIB=42.7
      GO TO 200
  180 CONTINUE
C *** HERE THE I-BEAM DEPTH EXCEEDS THE AMERICAN CHANNELS SPECS.
C *** SO WTIB IS ESTIMATED BY EXTRAPOLATION
      WTIB=3.31*(DDIB-10.)+15.3
C
  200 CONTINUE
C
C     LENGTH OF I-BEAM (FT)
      DLIB=DL+(DDOF+DDOB)/12.0
C
C     WEIGHT OF I-BEAM (LB)
      WTIB1=WTIB*DLIB
C
C     WEIGHT FOR TWO I-BEAMS (LB)
      WTIB2=WTIB1*2.0
C
C     I-BEAM MATERIAL COST ($)
      CTIB=CTIB1*WTIB2
C
C     I-BEAM WELDING COST ($)
      WLDIB=2.0*(DDOF+DDOB)*WLDL*WLDT/60.0
C
C
C     EVERY 6 FT ALONG THE BUNDLE LENGTH, THERE ARE TUBE SPACERS,
C     TUBE KEEPERS AND SUBE SUPPORTS
C     TO CALCULATE DETAILED MATERIAL AND LABOR COST OF THE SUPPORTS,
C     SUPPORTS DIMENSIONS MUST BE GIVEN
C
C     HERE, ASSUME THAT THE COST FOR EVERY 6 FT SUPPORTS IS CTSP1 ($)
C     CTSP1 IS PROPORTIONAL TO BUNDLE WIDTH
      AK=0.5
      CTSP1=AK*DHEDW
C
      ISUPP=INT(DL)/6
      IF (DL/6.0-FLOAT(ISUPP)) 202,202,204
  202 CONTINUE
      ISUPP=ISUPP-1
  204 CONTINUE
C
      SUPPM=CTSP1*FLOAT(ISUPP)
C
C     ASSUME THE ASSEMBLING COST FOR TUBE SUPPORTS IS THE SAME FOR
C     SUPPORTS MATERIALS
      SUPPL=SUPPM
C
      SUPP=CTIB+WLDIB+SUPPM+SUPPL
C
      SLABT=CTUBA+CTUBW+WLDIB+SUPPL
      SMATT=CTUBE+CTIB+SUPPM
  400 CONTINUE
      RETURN
      END



      SUBROUTINE CENT(J,N,KN,JHIGH)
      COMMON/EPA/TNMIN,TNMAX,TSAT(21),COSTT(21),X(10,21),XC(10),VAMAX,
     1VAMIN,VWMAX,VWMIN,XN,XP,SUBCL,QMIN,QMAX,PITCH,DIA,
     2RNGMX,RNGMN,TLMIN,TLMAX,TITDX,TITDN
C
C     THIS SUBROUTINE CALCULATES THE CENTROID. OF THE KN POINTS
C     ONLY POINT J IS NOT INCLUDED.
C
      NN=KN-1
      XNK=NN
      IF(JHIGH.NE.0) GO TO 350
      DO 100 I=1,N
      XC(I)=0.
  100 CONTINUE
      DO 200 I=1,KN
      DO 200 II=1,N
      XC(II)=XC(II)+X(II,I)
  200 CONTINUE
      DO 300 I=1,N
      XC(I)=(XC(I)-X(I,J))/XNK
  300 CONTINUE
      GO TO 500
C
C     IF THE CENTROID HAS BEEN CALCULATED FOR A PREVIOUS CASE,
C     THE NEW ONE IS SIMPLY THE OLD CENTROID LESS THE J POINT
C     WITH THE JHIGH POINT ADDED BACK IN.
C
  350 DO 400 I=1,N
      XC(I)=XC(I)+(X(I,JHIGH)-X(I,J))/XNK
  400 CONTINUE
  500 CONTINUE
      RETURN
      END
```

```
      SUBROUTINE CFIXM(VALUE,VAMIN,VAMAX,RESET,KERN,KERRO,NERC)
C *** LIMITS VALUES OF INPUT DATA AND STORES GREY ERROR MESSAGE CODES
      DIMENSION KERRO(1)
      IF (VALUE-VAMAX) 10,20,20
   10 IF (VAMIN-VALUE) 100,15,15
   15 VALUE=RESET
      GO TO 100
   20 VALUE=RESET
      CALL ERORG (NERC,KERRO,KERN)
  100 RETURN
      END
      SUBROUTINE CHANL(NFO,ZBYP,VALVE,NPUMP,PPGPM,PUMPC,IXNL,PUMPF,VFILL
     1,TANKC,CONTR,BLANN,SHIPCO,CAPIP,NTANK,INML)
      COMMON/BCK/XMCST(20),PIPDM(20),XSHOP(20),FIELD(20),EXJOT(20)
      DIMENSION MPRNT(44),VALVE(1)
      DATA MPRNT/10HINLET FEED,10HER LINE   ,10HOUTLET FEE,10HDER LINE
     1,          10HINLET HEAD,10HER       ,10HOUTLET HEA,10HDER
     2,          10H          ,10H          ,10H          ,10H
     3,          10H          ,10H          ,10H          ,10H
     4,          10H          ,10H          ,10H          ,10H
     5,          10H          ,10H          ,10H          ,10H
     6,          10H          ,10H          ,10H          ,10H
     7,          10H          ,10H          ,10H          ,10H
     8,          10HBAY CONTRO,10HL         ,10HCOND. PUMP,10H ISOLATION
     9,          10HRECVRY TUR,10HBINE ISO. ,10HBYPASS    ,10H
     1,          10HFILL PUMP ,10HISOLATION ,10HFILL DRAIN,10H
     2/
 1000 FORMAT(1H1,20X,9(1H*),38H   BACK-TO-BACK DRY TOWER PIPING COST ,
     112HBREAKDOWN   ,9(1H*),//,31X,30HDIAMETER     TOTAL         SYSTEM,/,
     233X,4H(IN),19X,5HTOTAL,/,13H A BAY PIPING,17X,20(1H-))
 1025 FORMAT(3X,I1,2H. ,2A10,6X,F7.2,F11.0)
 1075 FORMAT(39X,2X,9H---------,/,6X,10HPIPING/BAY,23X,F11.0,/,7X,
     1F4.0,5H BAYS,34X,F11.0,/,16H B SUPPLY PIPING,6H(TYPE ,I1,1H))
 5025 FORMAT(39X,2X,9H---------,/,39X,2F11.0,//,16H C RETURN PIPING,
     16H(TYPE ,I1,1H))
 5075 FORMAT(39X,2X,9H---------,/,39X,2F11.0,/)
 6000 FORMAT(13H D FILL LINES,19X,F7.2,2F11.0,/)
 6010 FORMAT(15H E BYPASS LINES,17X,F7.2,2F11.0,//,18H F VALVING(INSTALL
     13HED))
 6030 FORMAT(3X,I1,2H. ,2A10,6X,F7.2,F11.0)
 6040 FORMAT(40X,9(1H-),/,39X,2F11.0,/)
 6050 FORMAT(19H G PUMPS(INSTALLED),/,6H   1. ,I2,F8.0,10H GPM COND.,13X
     1,2F11.0,/,6H   2. ,I2,18H   10000 GPM FILL ,13X,2F11.0,/)
 6060 FORMAT(26H H STORAGE TANK(INSTALLED),/,1X,I4,2H -,F9.0,
     110H GAL TANKS,13X,2F11.0,/)
 6070 FORMAT(26H I CONTROLS(INSTALLED)    ,13X,2F11.0)
 6080 FORMAT(26H J NITROGEN BLANKETING    ,13X,2F11.0)
 6090 FORMAT(26H K SHIPMENT OF PIPING     ,13X,2F11.0)
 6250 FORMAT(52X,9(1H-),/,50X,F11.0)
 2010 WRITE(NFO,1000)
      TOTOX=0.
      DO 1050 I=1,4
      TOTO=XMCST(I)+XSHOP(I)+FIELD(I)
      TOTOX=TOTOX+TOTO
      WRITE(NFO,1025)I,MPRNT(2*I-1),MPRNT(2*I),PIPDM(I),TOTO
 1050 CONTINUE
      TTOV=ZBYP*TOTOX
      WRITE(NFO,1075)TOTOX,ZBYP,TTOV,INML
      TOTOX=0.
      DO 5000 I=1,6
      TOTO=XMCST(I+4)+XSHOP(I+4)+FIELD(I+4)+EXJOT(I+4)
      TOTOX=TOTOX+TOTO
      WRITE(NFO,1025)I,MPRNT(2*I+7),MPRNT(2*I+8),PIPDM(I+4),TOTO
 5000 CONTINUE
      WRITE(NFO,5025)TOTOX,TOTOX,INML
      TOTOX=0.
      DO 5050 I=1,6
      TOTO=XMCST(I+10)+XSHOP(I+10)+FIELD(I+10)+EXJOT(I+10)
      TOTOX=TOTOX+TOTO
      WRITE(NFO,1025)I,MPRNT(2*I+19),MPRNT(2*I+20),PIPDM(I+10),TOTO
 5050 CONTINUE
      WRITE(NFO,5075)TOTOX,TOTOX
      TOTO=XMCST(17)+XSHOP(17)+FIELD(17)+EXJOT(17)
      WRITE(NFO,6000)PIPDM(17),TOTO,TOTO
      TOTO=XMCST(18)+XSHOP(18)+FIELD(18)+EXJOT(18)
      WRITE(NFO,6010)PIPDM(16),TOTO,TOTO
      TOTOX=0.
      DO 6020 I=1,6
      TOTOX=TOTOX+VALVE(I)
      J=5
      IF(I.EQ.1)J=1
      IF(I.GT.4)J=17
      WRITE(NFO,6030)I,MPRNT(2*I+31),MPRNT(2*I+32),PIPDM(J),VALVE(I)
 6020 CONTINUE
      WRITE(NFO,6040)TOTOX,TOTOX
      WRITE(NFO,6050)NPUMP,PPGPM,PUMPC,PUMPC,IXNL,PUMPF,PUMPF
      WRITE(NFO,6060)NTANK,VFILL,TANKC,TANKC
      WRITE(NFO,6070)CONTR,CONTR
      WRITE(NFO,6080)BLANN,BLANN
      WRITE(NFO,6090)SHIPCO,SHIPCO
      WRITE(NFO,6250)CAPIP
      RETURN
      END
```

```
      SUBROUTINE CONST(J,DELT)
      COMMON/EPA/TNMIN,TNMAX,TSAT(21),COSTT(21),X(10,21),XC(10),VAMAX,
     1VAMIN,VWMAX,VWMIN,XN,XP,SUBCL,QMIN,QMAX,PITCH,DIA,
     2RNGMX,RNGMN,TLMIN,TLMAX,TITDX,TITDN,TSATA,TSATZ,XHEAT(21)
      COMMON/SCOND/TTDMN,TTDMX,TISUM(21)
C
C     THIS SUBROUTINE DETERMINES IF POINT J IS WITHIN CONSTRAINTS
C     IF IT IS NOT,IT IS MOVED A SMALL PERCENTAGE,DELT,OF THE DISTANCE
C     FROM THE BOUNDARY TO THE CENTROID
```

```
C
      IF(X(1,J).LT.TSATA)X(1,J)=TSATA-DELT*(TSATA-XC(1))
      IF(X(1,J).GT.TSATZ)X(1,J)=TSATZ-DELT*(TSATZ-XC(1))
      TSAT(J)=X(1,J)
      CALL QTURB(XHEAT(J),TSAT(J),1.,2)
      IF(X(6,J).LT.TTDMN)X(6,J)=TTDMN-DELT*(TTDMN-XC(6))
      IF(X(6,J).GT.TTDMX)X(6,J)=TTDMX-DELT*(TTDMX-XC(6))
      SUBCL=X(6,J)
      TITD=AMIN1(TITDX,(TSAT(J)-SUBCL+50.))
      IF(X(2,J).LT.TITDN)  X(2,J)=TITDN -DELT*(TITDN -XC(2))
      IF(X(2,J).GT.TITD)   X(2,J)=TITD   -DELT*ABS(TITD   -XC(2))
      IF(X(3,J).LT.RNGMN)  X(3,J)=RNGMN-DELT*(RNGMN-XC(3))
      RNG=AMIN1(RNGMX,X(2,J)*.99,(TSAT(J)-SUBCL-32.))
      IF(X(3,J).GT.RNG)     X(3,J)=RNG   -DELT*ABS(RNG   -XC(3))
      IF(X(4,J).LT.TLMIN) X(4,J)=TLMIN-DELT*(TLMIN-XC(4))
      IF(X(4,J).GT.TLMAX) X(4,J)=TLMAX-DELT*(TLMAX-XC(4))
      IF(X(5,J).LT.TNMIN) X(5,J)=TNMIN-DELT*(TNMIN-XC(5))
      IF(X(5,J).GT.TNMAX) X(5,J)=TNMAX-DELT*(TNMAX-XC(5))
      RETURN
      END
```

```
      SUBROUTINE COSTER(J,VAIR,VH2O,KKILL)
      COMMON/EPA/TNMIN,TNMAX,TSAT(21),COSTT(21),X(10,21),XC(10),VAMAX,
     1VAMIN,VWMAX,VWMIN,XN,XP,SUBCL,QMIN,QMAX,PITCH,DIA,
     2RNGMX,RNGMN,TLMIN,TLMAX,TITDX,TITDN,TSATA,TSATZ,XHEAT(21)
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),IDUM6(4),MM,IDUM8(4),NTP,IDUM9,NTT
      COMMON DUMW(32),DEN12(2,2),DUMW2(8),DBW,DUMWW(9),DLTS,
     1DNZ(2),DUME22(2),
     1DTF,DUME5(3),PT,DUME6(28),HPFNC,DUMW1(7),QDUT,DUMM(8),TIN(2),
     2TOUT(2),DUME7(14),VAPP,DUME1(3),DFAN,DUME4(2),VISLZ(7),DUME3(7),
     3W(2),DUME8(98),ZBYP,ZBUP,DUME10,ZFAN,DFANI,DLOV,DUME12(4),WD(2),
     4VAPPI,DUME15(3),TIND(2),TOUTD(2),DUME16(3),QD(7),DUME17(6),
     5DNZI(2),DUME19(11),ZTPD,ZNTD,COST(7)
      COMMON SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/TRACE/SSSUM(9),IISUM(3)
      COMMON/PEN/ATTR(20),DATTR(20),AMBTPT(20),BCAPC,NATTR,CAPCST,CMAIN,
     1MACC,AFCR2,XLVL,FLCST,CAPBS,PLDFT(20),STMCT,CUTMP,SHELP,BHTRT(6)
      COMMON/STIN/XLDFT(6),BP(28),HTRTD(28,6),HTRJD(28,6),NLODS,NBKPR
     1,PLOAD,BPMNM(6),TPMNM(6)
      COMMON/JUMP/JAKE,TINMX,NOO2I,DTN2I,NOO1I,NFPIN,NOO2O,NOO1O
      COMMON/GOFAN/KFANG
      COMMON/PIPE/XDIA(20),XLGT(20),NN1,NN2,XTOWR,PLNMH,TTTBH,VX,VN
     1,VAVE
      COMMON/HEAD/TOPHD,WRTHD,DPCON,SPDP,RTDP
      COMMON/JAN7/WBMAX,PBPMN,TBPMN,CPEFF,WTEFF,PBPHT,EBPOM,PPOM,CWRTI,
     1SCPMP,CCPMP,FDMAX,MXFBL,SPRNZ,SPRHT,CWTLV,DPPCT,PDMAX,CONCT
      COMMON/PRSUM/XPRIC(12,21)
      COMMON/PERFO/AUXMW(20,21),TURMW(20,21),ZLOAD(20,21)
      COMMON/PASIT/TBUCK
      COMMON/SCOND/TTDMN,TTDMX,TISUM(21)
      COMMON/BCKPR/BCKMN,BCKMX
      COMMON/SCRAT/CLFAC,KMETL,KGAGE,CITEM(10,15),GTITD
      DIMENSION EKW(10),GSLOD(10)
C *** SET DATA FOR SURFACE CONDENSER DESIGN
C *** KCOND - IS  MULTIPRESSURE CODE- 1=SINGLE PRESS,  2= TWO PRESSURE
C *** SET TUBE METAL CODE FOR CARBON STEEL (KMETL=9)
C *** SET CODE NO. OF TUBE SHEET METAL USING CARBON STEEL  MN=2
C *** SET THE GAGE OF THE TUBE TO BWG=16, THICK OF .065 INCH (KGAGE=5)
C *** CPLB = COST/LB OF CONDENSER TUBES-IF ZERO,ESTIMATE IS MADE
C *** IN SCSBP
C *** SET ACCELERATION DUE TO GRAVITY
C *** DPMAX = MAX. PRESSURE DROP IN PSI
C *** CLMIN - MIN. ALLOWABLE TUBE LENGTH FOR DESIGN ONLY
C *** VMIN - MIN. ALLOWABLE TUBE VELOCITY
C *** VMAX - MAX. ALLOWABLE TUBE VELOCITY
C *** SET CLEANINESS FACTOR - CLFAC
      DATA KCOND,MN/2,2/
      DATA CPLB,GC,DPMAX,CLMIN,VMIN,VMAX/0.,32.2,15.,20.,6.,7./
C
C     THIS SUBROUTINE FINDS THE OBJECT FUNCTION FOR THE J POINT. THE
C     OBJECT FUNCTION IS THE TOTAL COST OF THE DRY COOLING TOWER SYSTEM
C
      NSUM=J
      COLWS=TBUCK
C *** COOLING TOWER DESIGN IS BASED ON 100 PCT. TURBINE LOAD
      PLOAD=1.0
      KMETL=9
      KGAGE=5
      CLFAC=.85
      BPLKW=BCAPC*1000.
C *** DESIGN BUNDLES TO BE AS CLOSE TO MAXIMUM WIDTH AS POSSIBLE
C *** ALLOW 2 INCHES ON EACH SIDE FOR STRUCTURE AND .0625 INCHES ON
C *** EACH SIDE CLEARANCE FROM WALL TO TUBE
      WTDAV=WBMAX*12.-4.125-DTF+PT
C *** FIND NUMBER OF TUBES/BUNDLE
      ZNTZ=AINT(WTDAV/PT)*XN
C *** STAGGERED BUNDLE HAS FEWER TUBES
      ZNTZ=ZNTZ-AINT((XN+.01)/2.)
C *** FIND TOTAL NUMBER OF BUNDLES
      ZBYP=AINT(X(5,J)/ZNTZ-.001)+1.0
C *** MAKE NUMBER OF BUNDLES A MULTIPLE OF 4  SO THAT BACK-TO-BACK
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```
C *** PIPING CAN ENTER IN THE MIDDLE.
      ZZBYP=AMOD(ZBYP,4.*ZBUP)
      IF(ZZBYP.GT..001)ZBYP=ZBYP-ZZBYP+4.*ZBUP
C *** MAKE ACTUAL TUBES/BUNDLE AN EVEN MULTIPLE OF XN
      ZNTD=AINT(X(5,J)/ZBYP-.001)+1.0
C *** IF ZZ IS ZERO THEN YOU DO NOT HAVE TO INCREASE ZNTD
      ZNNN=ZNTD+AINT((XN+.01)/2.)
      ZZ=AMOD(ZNNN,XN)
      IF(ZZ-.001)7,7,4
    4 IF(ZZ-XN/2.)5,6,6
    5 ZNTD=ZNTD-ZZ
      GO TO 8
    6 ZNTD=ZNTD+XN-ZZ
C *** CHECK THAT BUNDLE IS STILL WITHIN WIDTH LIMITATIONS
    8 IF(PT*(1.+FLOAT(INT((ZNTD-.01)/XN)))-WTDAV)7,7,9
    9 ZNTD=ZNTD-XN
C *** CALCULATE ACTUAL NUMBER OF TUBES
    7 X5NEW=ZBYP*ZNTD
C *** MAKE ZBYP THE NUMBER OF BAYS
      ZBYP=ZBYP/ZBUP
C *** PUT TEMPERATURES IN DEGREE RANKINE
      T=TSAT(J)-SUBCL
      TIND(1)=TCONV(T,1,1)
      TIND(2)=TIND(1)-X(2,J)
      TOUTD(1)=TIND(1)-X(3,J)
C *** DETERMINE CP OF WATER BASED ON AVERAGE TEMPERATURE
      T=.5*(TIND(1)+TOUTD(1))
      T=T-459.67
      CALL PPAUT1(T,CP,DEN,D1,D3,KODE)
C
C *** FIND WATER VELOCITY IN FT/SEC.
      VH2O=XHEAT(J)*XP/X(3,J)/X(5,J)/19.635/DIA**2/CP/DEN
C *** SET KKILL
C *** CHECK IF WATER VELOCITY IS WITHIN LIMITS
      KKILL=0
      IF(VH2O-(VWMAX+.01)) 20,20,10
C *** WATER VELOCITY IS TOO HIGH
   10 KKILL=1
      GO TO 100
   20 IF(VH2O-(VWMIN-.01)) 30,40,40
C *** WATER VELOCITY IS TOO LOW
   30 KKILL=2
      GO TO 100
   40 X(5,J)=X5NEW
C *** SET UP VARIABLES TO MAKE COMPATABLE WIITH AC PROGRAM.
C *** ONCE VARIABLES ARE SET  CALL SUBROUTINE SUPER TO FIND VAIR .
      KCI=2
      DLOV=X(4,J)
      WD(1)=XHEAT(J)/X(3,J)/CP
      KFANG=0
      JAKE=2
      CALL SUPER
C *** IF KGO=2 THEN KILL THE PROGRAM.  THIS CAN BE DONE BY SETTING
C *** NPAGE=200,  SINCE THE MAXIMUM NUMBER OF OUTPUT PAGES IS 200
      IF(KGO-1) 60,60,50
   50 NPAGE=200
      GO TO 100
C *** IF KER=11 THEN THE AIR-SIDE VELOCITY WAS TOO HIGH. SET VAIR
C *** AN ARBITRARY VALUE ABOVE MAX. AIR VELOCITY
   60 IF(MM.EQ.0)GO TO 80
      DO 65 I=1,MM
      IF(KERR(I) -11) 65,70,65
   65 CONTINUE
      GO TO 80
   70 VAIR=VAMAX*1.15
      KKILL=3
      MM=0
      GO TO 100
   80 VAIR=VAPP
C *** IF AIR VELOCITY, VAIR, IS OUTSIDE MAXIMUM AND MINIMUM VELOCITY
C *** THEN RETURN WITHOUT CALCULATING COST
      IF(VAIR-(VAMAX+.01)) 94,94,92
C *** AIR VELOCITY IS TOO HIGH
   92 KKILL=3
      MM=0
      GO TO 100
   94 IF(VAIR-(VAMIN-.01)) 96,98,98
C *** AIR VELOCITY IS TOO LOW
   96 KKILL=4
      MM=0
      GO TO 100
C *** FOR INITIAL COMPLEX DO NOT LET VAIR GO ABOVE 1000 FPM
   98 IF(IISUM(1).GT.0)GO TO 95
      IF(VAIR.GT.1010.)GO TO 92
C *** CALL OUTPE TO PERFORM BUNDLE AND FAN COST CALCULATION
   95 CALL OUTPE
      COSTT(J)=SSSUM(8)
      TISUM(J)=SUBCL
C
C *** ADD IN CAPITAL COST OF INCREASING STEAM SUPPLY SYSTEM (INSTALLED)
      XPRIC(6,J)=STMCT*1.E06*COST(2)
      COSTT(J)=COSTT(J)+XPRIC(6,J)
C *** IF CONCT IS ZERO ASSUME A SURFACE CONDENSER IS USED
      IF(CONCT-.001)102,102,103
  102 CALL SCDES(VMIN,VMAX,CLMIN,TLMAX,SSSUM(2),SSUM(12,J),W(1),KMETL,
     1KGAGE,VN,GC,PI,KCOND,CLFAC,DPMAX,CPLB,TSAT(J),BCKMX,BCKMN,DPCON,
     2DAY(1),CITEM,KNTR1,CPEFF,CMAIN,AFCR2,CAPCST,COST(2))
      DPCON=CITEM(1,10)
C *** SET FIRST GUESS TO BE USED IN RATING ROUTINES
      GTITD=SUBCL
      XPRIC(7,J)=CITEM(1,14)*1000.*COST(2)
      GO TO 104
  103 CONTINUE
C *** ADD IN CONDENSER COST BASED ON DESIGN STEAM FLOW (USE LATENT
C *** HEAT FOR 18 INCHES HG) CONCT IS INSTALLED COST.
      XPRIC(7,J)=CONCT*QOUT/985.*COST(2)
  104 CONTINUE
      COSTT(J)=COSTT(J)+XPRIC(7,J)
      CALL GEOM2(CAPIP)
C *** ADD IN COST OF PIPING,PUMPS,VALVES,ETC.
      XPRIC(1,J)=CAPIP*COST(2)
      COSTT(J)=COSTT(J)+XPRIC(1,J)
C
C *** CALL DPPIP TO DETERMINE AUX. POWER AT DESIGN POINT
      CALL DPPIP
      HPPMP=W(1)/60.*TOPHD/CPEFF/33000.
      HPWRT=W(1)*WRTHD*WTEFF/8.82/3600./DEN12(2,1)
      HPP=HPPMP-HPWRT
      DUMX1=HPPMP*.0007457
      DUMX2=HPWRT*.0007457
      DUMX3=.0007457*ZFAN*ZBYP*HPFNC
      ISUM(2,J)=DUMX1+.49
      ISUM(7,J)=DUMX2+.49
      ISUM(11,J)=DUMX3+.49
      SSUM(13,NSUM)=.0007457*(HPP+ZFAN*ZBYP*HPFNC)
C *** ADD IN 200 KW INSTALLED CAPACITY IN CASE EVAP. TOWER IS NEEDED
      SSUM(13,NSUM)=SSUM(13,NSUM)+.2
C
C *** ADD IN COST OF WATER RECOVERY TURBINES. USE INSTALLED COST/KW
      XPRIC(8,J)=CWRTI*.7457*HPWRT*COST(2)
      COSTT(J)=COSTT(J)+XPRIC(8,J)
C
C *** ADD IN INSTALLED COST OF ELECTRICAL SUBSTATION AND TRANSMISSION
C *** LINES. OVERHEAD LINES ARE 27 DOLLARS/FOOT. ASSUME SUBSTATION
C *** IS AT POWER PLANT
      CAUX=580000.*SQRT(SSUM(13,NSUM)/20.)
      CAUX=CAUX+27.*1.15*(DPPCT+ZBYP/2.*SSUM(3,NSUM)*ZBUP)
      XPRIC(9,J)=CAUX*COST(2)
      COSTT(J)=COSTT(J)+XPRIC(9,J)
C
C *** ADD IN 12 PCT. FOR INTEREST DURING CONSTRUCTION
      XPRIC(10,J)=.12*COSTT(J)
      COSTT(J)=COSTT(J)+XPRIC(10,J)
C *** IF OPTIMIZATION IS THROUGH, DO NOT RUN OFF-DESIGN PERFORMANCE
      IF(KNTR1.EQ.1) GO TO 100
C *** ADD THE FOLLOWING SECTION TO FIND OFF DESIGN PERFORMANCE.
C *** SET VARIABLES  NEEDED BY SUPER
      KCI=1
      WD(1)=W(1)
      VAPPI=VAPP
      DLOV=VISLZ(1)
      ZTPD=NTP
      ZNTD=NTT
      DNZI(1)=DNZ(1)
      DNZI(2)=DNZ(2)
      DFANI=DFAN
      JAKE=3
      KREEP=0
C *** SET ENERGY PENALTY TO ZERO
      ENPEN=0.0
      PRICE(2,J)=0.
      ANNFL=0.0
      YFUEL=0.0
C *** CALL SUPER TO FIND ITD
      DO 200 I=1,NATTR
C *** IF COST IS ALREADY HIGHER THAN IT WAS BEFORE, THEN DO NOT BOTHER
C *** TO RUN OFF-DESIGN PERFORMANCE. THIS WILL MAKE THE TOTAL COST
C *** WRONG SINCE THE PENALTY COST HAS NOT BEEN FULLY DETERMINED. ALSO
C *** THE CAPACITY COST MAY BE BASED ON THE PREVIOUS COSTER CALL.
      IF(IISUM(1))107,107,105
  105 IF((COSTT(J)+ENPEN+YFUEL+PRICE(2,J))-COLWS)107,107,201
  107 CONTINUE
      KREEP=I
C
C *** SET PLANT LOAD AND NOMINAL OUTPUT FOR THAT LOAD
      XLOAD=PLDFT(I)
      PLOAD=XLOAD
      TBXXX=GRS(XLDFT,1,TPMNM,1,PLOAD,NLODS,XXXX)
C *** PLANT OUTPUT IS COMPARED AGAINST LOAD DEMANDED - NOT THE OUTPUT
C *** OF AN EQUIVALENT WET TOWER PLANT
      XPLKW=BPLKW*XLOAD
C *** SET HOURS AT THIS CONDITION
      HRS=DATTR(I)
      IINCL=0
      NRLOD=1
      PTOL=50.
      BOTP=.7*XLOAD
      TOPP=1.
      TIND(2)=ATTR(I)+459.67
C *** IF LAST AMBIENT HAD FAN CONTROL AND NEW AMBIENT IS LOWER WITH A
C *** LOWER LOAD, THEN START FAN CONTROL IMMEDIATELY
      IF(I.EQ.1)GO TO 109
      IF(JFAN.EQ.0)GO TO 109
      IF(ATTR(I).LT.ATTR(I-1).AND.XLOAD.LT.(FLOAD+.0001))GO TO 115
  109 JFAN=0
      FLOAD=PLOAD
C *** IF AMBIENT IS BELOW CUTOFF FOR FAN CONTROL, START FAN CONTROL
      IF(ATTR(I).LT.(TBXXX-SUBCL-SSSUM(9)))GO TO 115
  110 CONTINUE
      KFANG=1
      CALL SUPER
C *** START CONTINUOUS FAN CONTROL WHEN TIN(1) GOES BELOW MINIMUM
C *** ALLOWABLE TEMPERATURE.
C *** SEE IF TIN(1) IS WITHIN 2 DEGREES
      IF((TIN(1)+2.)-(TBXXX-SUBCL+459.67))114,150,150
  114 MM=0
  115 CONTINUE
      CALL QTURB(QFANC,TBXXX,PLOAD,2)
C *** IF CONCT IS ZERO THEN ASSUME A SURFACE CONDENSER IS USED
      IF(CONCT-.001)120,120,130
  120 CALL SCMPR(TBXXX,QFANC,W(1),CLFAC,KMETL,KGAGE,BCKMX,BCKMN,
     1CITEM(1,11),CITEM(1,4),CITEM(1,13),GTITD,CITEM(1,15),TIND(1),
     2TOUTD(1))
      SUBCL=TBXXX-TIND(1)
      GTITD=SUBCL
      TIND(1)=TIND(1)+459.67
      TOUTD(1)=TOUTD(1)+459.67
      GO TO 140
  130 CONTINUE
C *** FOR JET COND. ASSUME TTD IS PROPORTIONAL TO Q
      SUBCL=QFANC*TISUM(J)/SSUM(8,J)/1.E06
      TIND(1)=TBXXX+459.67-SUBCL
C *** CONVERGE ON CP
      LQ=1
      CPX=1.
  133 TOUTD(1)=TIND(1)-QFANC/W(1)/CPX
      XX=.5*(TOUTD(1)+TIND(1))
      CP1=1.191328-7.002932E-4*XX+6.3408E-7*XX*XX
      IF(ABS(1.-CP1/CPX)-.004)140,140,135
  135 IF(LQ-5)137,140,140
  137 LQ=LQ+1
      CPX=CP1
      GO TO 133
  140 CONTINUE
      TOUTD(2)=0.
      KCI=2
      KFANG=0
C *** KFANG INDICATES FAN CONTROL FOR THIS PLOAD
C *** JFAN INDICATES ANY FAN CONTROL FOR THIS AMBIENT
C *** FLOAD IS LOAD FAN CONTROL STARTED FOR THIS AMBIENT
      IF(JFAN.EQ.0)FLOAD=PLOAD
      JFAN=1
      IF(PLOAD.GT.FLOAD)FLOAD=PLOAD
      VAPSTR=VAPP
      VAPPI=0.
      QD(1)=0.
      CALL SUPER
      KCI=1
      VAPPI=VAPSTR
  150 CONTINUE
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C *** DETERMINE TOTAL KW FOR FANS
      TOTKW=ZFAN*ZBYP*HPFNC*.7457
C
C *** FIND PUMP HEAD IN FEET OF WATER AND CALCULATE HP
      CALL DPPIP
      HPPMP=W(1)/60.*TOPHD/CPEFF/33000.
C *** APPLY POWER FROM WATER RECOVERY TURBINE TO PUMPING POWER
      HPWRT=W(1)*WRTHD*WTEFF/8.82/3600./DEN12(2,1)
      HPP=HPPMP-HPWRT
C *** ADD PUMPING KW ON TO FAN KW
      TOTKW=TOTKW+HPP*.7457
C
C *** IF EVAP. TOWER IS NEEDED FOR AUX. COOLING, ADD 200 KW TO
C *** OPERATE TOWER PUMP AND FAN
      IF((TOUT(1)-459.67)-95.)152,152,151
  151 TOTKW=TOTKW+200.
  152 CONTINUE
C
C *** DETERMINE KW FOR TURBINE AND FIND DIFFERENCE FROM  BASE PLANT KW
      TZZ=TIN(1)+SUBCL
C *** HEAT RATE RATIO IS BASED ON NOMINAL BACK PRESSURE INPUTTED
      CALL HTURB(TZZ,HRATO,PLOAD,HRTBS,PBPHT)
  154 TURKW=BPLKW*PLOAD/HRATO
      DELKW=XPLKW-TURKW
C
C *** FIND TURBINE HEAT RATE
  159 HRTRB=HRATO*HRTBS
C *** DETERMINE IF PLANT OUTPUT IS CLOSE ENOUGH TO DEMANDED OUTPUT
      EZ=TURKW-TOTKW-XPLKW
      IF(ABS(EZ).GT.PTOL)GO TO 180
  160 IF(I-1)162,162,165
C *** CALCULATE CAPACITY PENALTY AT HIGHEST AMBIENT TEMPERATURE AND
C *** STORE MAXIMUM KW PENALTY FOR TURBINE AND AUXILLARIES
  162 TOTMX=TOTKW
      SSUM(6,J)=PSL(TZZ-459.67)
      DELMX=DELKW
      DKWMX=TOTMX+DELMX
      CPPEN=DKWMX*AFCR2*CAPCST
      COSTT(J)=COSTT(J)+CPPEN
C
C *** EVAP. TOWER FOR AUX. COOLING IS ASSUMED TO COST 300000. DOLLARS
C *** INSTALLED. THE HEAT LOAD FOR THE AUX. COOLING IS INCLUDED IN
C *** QTURB AS PART OF 10 PCT. STACK LOSS
      XPRIC(11,J)=0.
      IF((TOUT(1)-459.67)-95.)164,164,163
  163 XPRIC(11,J)=300000.*COST(2)
      COSTT(J)=COSTT(J)+XPRIC(11,J)
  164 CONTINUE
C
C *** ADD UP INCREMENTAL FUEL COST - COMPARE TO DEMANDED LOAD AT THE
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C *** HEAT RATE INPUTTED FOR THIS PURPOSE
C *** IT IS POSSIBLE TO GET CREDIT AT PART LOAD CONDITIONS
  165 BHTR=GRS(XLDFT,1,BHTRT,1,XLOAD,NLODS,XXXX)
      ANN=HRS*FLCST*1.E-06
      ANN1=ANN*HRTRB*TURKW
      ANNFL=ANNFL+ANN1
      YFUEL=YFUEL+ANN1-ANN*BHTR*XPLKW
C *** ADD UP O+M CHARGES FOR HEAT REJECTION SYSTEM
      PRICE(2,J)=PRICE(2,J)+EBPOM*HRS*TURKW*1.E-03
  168 CONTINUE
      ZLOAD(I,J)=PLOAD
      AUXMW(I,J)=TOTKW
      TURMW(I,J)=TURKW
      GO TO 200
C *** DETERMINE IF LOAD NEEDS TO BE INCREASED OR DECREASED
  180 IF(EZ.LT.0.)GO TO 182
      IF(PLOAD.GT..02)GO TO 183
      GO TO 160
C *** IF PLOAD IS CLOSE TO 1 YOU CAN NOT INCREASE THE LOAD
  182 IF(PLOAD-.99)183,183,190
C *** CHECK IF LOAD HAS BEEN CHANGED
  183 IF(IINCL)184,184,185
C *** START TO CHANGE LOAD
  184 IINCL=1
      GSLOD(1)=XLOAD
      GSLOD(2)=GSLOD(1)*XPLKW/(EZ+XPLKW)
  185 IF(EZ.GT.0.)TOPP=PLOAD
      IF(EZ.LT.0.)BOTP=PLOAD
C *** USE NEWTON RAPHESON TO CONVERGE ON TURBINE OPERATING POINT
  186 EKW(NRLOD)=EZ
      CALL NRCON(NRLOD,GSLOD,EKW,KER,54,1.E-8,JZ,10)
      IF(JZ-1)188,160,187
  187 CALL ERORF(KER,KERR,KGO,MM)
      GO TO 160
  188 PLOAD=GSLOD(NRLOD)
      IF(PLOAD.GT.BOTP.AND.PLOAD.LT.TOPP)GO TO 189
C *** SET PLOAD HALF WAY IN BETWEEN BEST GUESSES
      PLOAD=(BOTP+TOPP)/2.
      GSLOD(NRLOD)=PLOAD
  189 MM=0
      TBXXX=GRS(XLDFT,1,TPMNM,1,PLOAD,NLODS,XXXX)
C *** IF FAN CONTROL HAS OCCURRED AT A HIGHER LOAD GO TO FAN CONTROL
      IF(JFAN.EQ.0)GO TO 110
      GO TO 115
C *** MUST GO TO OUTSIDE SOURCE FOR POWER. DETERMINE HOW MUCH POWER
  190 PPPWR=(-1.)*EZ
      IF(ATTR(I)-CUTMP)194,194,192
C *** POWER MUST COME FROM PEAK PLANT
  192 ENPEN=ENPEN+HRS*COST(6)*PPPWR/1000.
      GO TO 160
```

```
C *** POWER CAN COME FROM SYSTEM
  194 ENPEN=ENPEN+HRS*SHELP*PPPWR/1000.
      GO TO 160
  200 CONTINUE
  201 CONTINUE
C *** RESET VARIABLES SO THAT OPTIMIZATION CAN CONTINUE
      KCI=2
      DFANI=0.
      TOUTD(2)=0.
      DNZI(1)=0.
      DNZI(2)=0.
      VAPPI=0.
      QD(1)=0.0
C *** ADD ENERGY PENALTY TO TOTAL COST
      COSTT(J)=COSTT(J)+ENPEN+YFUEL+PRICE(2,J)
C
      SSSUM(8)=COSTT(J)*1.E-03
      XPRIC(2,J)=CPPEN
      XPRIC(3,J)=ENPEN
      XPRIC(4,J)=COSTT(J)
      XPRIC(5,J)=YFUEL
      XPRIC(12,J)=ANNFL
  101 CONTINUE
  100 RETURN
      END
```

```
      SUBROUTINE DPAIR
C *** CALC. OF AIR SIDE PRESSURE DROP-EXCEPT FOR FRICTION CALC. BY DPFRA
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
```

```
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/FAN/EFFAN,NBLAD,HPMSP
      COMMON/JUMP/JAKE,TINMX,NOO2I,DTN2I,NOO1I,NFPIN,NOO2O,NOO1O
      COMMON/GOFAN/KFANG
      COMMON/JAN7/WBMAX,PBPMN,TBPMN,CPEFF,WTEFF,PBPHT,EBPOM,PPOM,CWRTI,
     1SCPMP,CCPMP,FDMAX,MXFBL,SPRNZ,SPRHT,CWTLV,DPPCT,PDMAX,CONCT
      TAV(2)=0.5*(TIN(2)+TOUT(2))
C *** HORSE POWER AND EFFICIENCY WILL NOT CHANGE AT OFF-DESIGN AMBIENTS
C *** LOUVERS WILL CONTROL THE PRESSURE DROP TO REMAIN THE SAME AS
C *** AMBIENTS INCREASE.
      IF(KFANG.EQ.1)GO TO 400
C *** FOR DESIGN, FAN SHOULD BE SIZED FOR COLD AMBIENT - NOT DESIGN
C *** AMBIENT.  THIS FAN DESIGN TEMP IS INPUTTED AS TAMB
      IF(JAKE.EQ.3)GO TO 19
C *** STORE VARIABLES THAT WILL MOMENTARILY BE CHANGED TO DESIGN FAN
      STJ1=VIS(2)
      STJ2=DEN(2)
      STJ3=REA(2)
      STJ4=TIN(2)
      STJ5=TOUT(2)
      STJ6=TAV(2)
      LLIT=0
      TIN(2)=519.67
C *** ASSUME AT FAN DESIGN TEMPERATURE, AIR TEMP RISE IS ABOUT 40 DEGREE
      TOUT(2)=TIN(2)+40.
      TAV(2)=.5*(TIN(2)+TOUT(2))
      T=TAV(2)-459.67
      DEN(2)=FALT/TAV(2)*39.68863
      VIS(2)=.00905+1.191E-04*(T+200.)**.775
      REA(2)=GAMAX*DFR/VIS(2)/29.06
   19 CONTINUE
      CALL DPFRA(VIS(2),0,TAV(2),DFR,DEN(2),CFP,DKL,1,ZNTR,
     1 GAMAX,DPAF,REA(2))
      TR=TOUT(2)/TIN(2)
      DENAP=0.075*530./TIN(2)*FALT
      RV2=DENAP*(VAPP /60.0)**2/(64.34*144.0)
C
C *** IF ZFAN AND DFAN HAVE NOT BEEN SET, DO SO NOW
C
      GO TO (31,31,49),JAKE
C *** START WITH 2 FANS/BAY OR 4 FANS/BAY
   31 ZFAN=2.
      HORSE=1.E10
      IF(ZBUP.LT.1.1)ZFAN=4.
C *** SET LARGEST DIAMETER FAN THAT MAY BE USED. ALLOW .5 FEET CLEARANCE
C *** BETWEEN THE FAN BELLS. BELL DIA. IS 1.2 OF THE FAN DIAMETER
   35 DFAN=AMIN1(FDMAX,DBW/12.*ZBUP/1.2,(DLTE/12./ZFAN/1.2-.5/1.2))+
     1.9999
C *** FIND NEXT SMALLER FAN
   39 IT=DFAN-.999
      IF(IT-14)46,46,44
   44 IF((-1)**IT)45,46,46
   45 IT=IT-1
   46 DFAN=IT
C *** CALCULATE FAN AREA BY SUBTRACTING HUB BLOCKAGE(HUB DIA=.3*DFAN)
      AFAN=ZFAN*.7854*.91*DFAN**2
      RFNPL=AFAN/(APPR*ZBUP)
C *** SET MAXIMUM NUMBER OF BLADES
      NBLAD=MXFBL
C *** SET 24 FOOT FAN AS MINIMUM SIZE
      IF(DFAN.LT.23.5)GO TO 242
   49 R2=AMAX1(1.0,1.0/RFNPL**2)
      S2=RAPMX**2
   64 CKINP=0.5-0.4*RFNPL
   66 CKD=1.0+TR*(R2-1.0+CKINP)
   70 DPAD=CKD*RV2
      HRECV=RV2*TR*R2*.3
      DPAD=AMAX1(0.0,DPAD-HRECV)
   78 CONTINUE
      CKM=(TR-1.0)*(1.0+S2)
      DPAM=CKM*RV2
  100 CKFNG=0.25*R2*TR
  144 CKLOV=1.8
      DPAW=RV2*(CKFNG+CKLOV)
C *** FLOW PER FAN IS EVALUATED
      WAPF=W(2)/(ZBYP*ZFAN)
  190 DENFN=DENAP/TR
  200 QA=WAPF/DENFN
C *** TOTAL STATIC DROP IS SUM OF ACCESSORY,FRICTION AND MOMENTUM CHANGE
C *** THE FRICT. DPAF IS CORRECTED BY BUNDLE IN SERIES BY CERRECTING NTR
      DPTOT(2)=DPAF+DPAW+DPAM
      D1=(DPTOT(2)+DPAD)*100.0
C *** FIND FAN EFFICIENCY AND HORSE POWER REQUIRED
C *** IF KFANG=0 AND JAKE=3  THEN WE HAVE FAN CONTROL.  USE THE FAN
C *** EQUATION WITH DESIGN EFFICIENCY
      IF(JAKE.EQ.2)GO TO 201
      HPFNC=D1*QA/EFFAN/1.378168E06
      GO TO 270
  201 XBLAD=NBLAD
      FLCFM=QA/60.E03
      PD11=D1*.27673
C *** ASSUME 12000 TIP SPEED
      DATA VTIPA/12000./
      CALL FANCON(Z1,Z2,Z3,K4,Z5,KSTEP,Z4,EFFAN,HPFNC,DFAN,DENFN,
     1        FLCFM,PD11,NBLAD,VTIPA,Z6)
C *** USE GEAR BOX EFFICIENCY OF .97 AND MOTOR EFFICIENCY OF .93
      EFFAN=EFFAN*.97*.93
      HPFNC=HPFNC/.97/.93
C
C *** IF LLIT=1 THEN IT IS GOING THROUGH ONCE MORE AT THE OPTIMUM DESIGN
      IF(LLIT)215,215,255
  215 IF(KSTEP)240,220,242
C *** CHECK IF HORSE POWER IS SMALLER THAN PREVIOUS HORSE POWERS
C *** AND TRY NEXT FAN DIAMETER OR NEXT NUMBER OF BLADES
  220 IF(HPFNC*ZFAN-HORSE)230,244,244
  230 HORSE=HPFNC*ZFAN
      DFANL=DFAN
      NBLDD=NBLAD
      ZFANL=ZFAN
      EFFNL=EFFAN
      AFANL=AFAN
      RFNLL=RFNPL
      GO TO 244
C *** IF STALL CONDITIONS(KSTEP=-2) OCCUR, THEN DECREASE THE FAN
C *** DIAMETER.  IF SMALLER FAN IS INDICATED(KSTEP=-1) THEN DECREASE
C *** THE NUMBER OF BLADES(TO A MINIMUM OF 8) OR DECREASE THE FAN DIA.
  240 IF(KSTEP.EQ.(-2))GO TO 39
  244 IF(NBLAD-8)39,39,241
  241 NBLAD=NBLAD-1
      GO TO 201
C *** IF BIGGER FAN IS INDICATED(KSTEP=+1)DECREASE NUMBER OF FANS
C *** PROVIDED THAT NUMBER OF BLADES IS AT MAXIMUM
  242 IF(NBLAD.LT.MXFBL)GO TO 39
      IF(ZFAN-1.5)250,250,245
  245 ZFAN=ZFAN-1.0
      GO TO 35
C *** RESET OPTIMUM VARIABLES
  250 HPFNC=HORSE/ZFANL
      DFAN=DFANL
      NBLAD=NBLDD
      ZFAN=ZFANL
      EFFAN=EFFNL
      AFAN=AFANL
      RFNPL=RFNLL
C *** GO THROUGH ONCE MORE AT THE OPTIMUM DESIGN(LLIT=1)
      LLIT=1
C *** USE BIGGEST AND MOST FANS IF NO FAN IS SUITABLE
      IF(HORSE-.9E10)49,49,31
  255 CONTINUE
C *** CHECK THAT A SUITABLE COMBINATION OF FAN SIZE AND NUMBER
C *** OF FANS HAS BEEN FOUND
      IF(HORSE -.9E10)270,270,260
  260 CONTINUE
C *** USE FAN EQUATION WITH EFFICIENCY OF .5
      EFFAN=.5
      HPFNC=D1*QA/EFFAN/1.378168E06
  270 WAPF=QA/60.0
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C *** STORE THE INLET SPECIFIED AIR SIDE STATIC DP - SHOULD BE IN PSI
  400 CONTINUE
C *** RESTORE VARIABLES THAT WERE DISTURBED TO DESIGN FAN
      IF(JAKE.NE.2)GO TO 450
      VIS(2)=STJ1
      DEN(2)=STJ2
      REA(2)=STJ3
      TIN(2)=STJ4
      TOUT(2)=STJ5
      TAV(2)=STJ6
  450 CONTINUE
      RETURN
      END


      SUBROUTINE DPFRA (VISAV,KFINP,TAV,DFR,DENAV,CFP,DKL,KFIN,ZNTR,
     1 GAMAX,DPFA,REAF)
C *** CALCULATE AIR SIDE PRESSURE DROP,BUNDLE, IN PSI
      DIMENSION CFP(3)
C *** GENERALIZED EQUATIONS START HERE
   50 DPFA=1.0
      CN=CFP(2)
C *** FOR FIN TUBES CHECK FOR TRANSITIONAL FLOW,KAYS AND LONDON
   60 IF (REAF*DKL/DFR-1000.0) 70,80,80
   70 CN=-0.4
      DPFA=(1000.0*DFR/DKL)**.155
   80 DPFA =CFP(1)*REAF**CN *DPFA
      DPFA=DPFA *GAMAX**2 *8.33E-12 *ZNTR /DENAV
  200 RETURN
      END
      SUBROUTINE DPPIP
C *** THIS ROUTINE DETERMINES THE HEAD ON A PUMP AND THE HEAD ON A
C *** WATER RECOVERY TURBINE TO MAINTAIN A 3 FEET ABOVE ATMOSPHERIC HEAD
C *** IN THE COIL. IT DOES THIS BY DETERMINING THE PRESSURE DROP OF THE
C *** PIPING BY ADDING UP L/D AS DESIGNED IN GEOM2. ASSUME A CONSTANT
C *** FRICTION FACTOR OF .011 AND A CONSTANT AVERAGE VELOCITY. PUMP
C *** SUCTION LOSSES ARE IGNORED.
C *** DUE TO TAPERED SUPPLY AND RETURN LINES AND VALVING, THERE IS NO
C *** MOMENTUM LOSS OR MALDISTRIBUTION
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/EPA/DUM1(270),SUBCL,DUM2(10)
      COMMON/PIPE/XDIA(20),XLGT(20),NN1,NN2,XTOWR,PLNMH,TTTBH,VX,VN
     1,VAVE
      COMMON/HEAD/TOPHD,WRTHD,DPCON,SPDP,RTDP
      COMMON/JAN7/WBMAX,PBPMN,TBPMN,CPEFF,WTEFF,PBPHT,EBPOM,PPOM,CWRTI,
     1SCPMP,CCPMP,FDMAX,MXFBL,SPRNZ,SPRHT,CWTLV,DPPCT,PDMAX,CONCT
      COMMON/JUMP/JAKE,DUM7(7)
      IF(JAKE.EQ.3)GO TO 36
      SPSUM=0.
      RTSUM=0.
C *** SUM UP SUPPLY L/D
      DO 10 I=1,10
      IF(XDIA(I)-.001)20,20,5
    5 SPSUM= SPSUM+XLGT(I)/XDIA(I)
   10 CONTINUE
   20 SPDP=SPSUM*VAVE**2*1.70775E-04
C *** SUM UP RETURN L/D
      DO 30 I=11,20
      IF(XDIA(I)-.001)35,35,25
   25 RTSUM=RTSUM+XLGT(I)/XDIA(I)
   30 CONTINUE
   35 RTDP=RTSUM*VAVE**2*1.70775E-04
C *** PRESSURE DROP IN CONDENSER SPRAY NOZZLES IS SPRNZ
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```
C *** FIND DISTANCE BETWEEN TOP OF COIL AND SPRAY NOZZLES
      CILHT=XTOWR+SPRHT
   36 CONTINUE
      IF(CONCT-.001)70,70,37
   37 CONTINUE
C *** FIND JET CONDENSER PRESSURE IN FEET OF WATER
      CONPR=PSL(TIN(1)+SUBCL-459.67)*1.133
C *** FIND WATER RECOVERY TURBINE HEAD IN FEET
C *** NECESSARY TO KEEP COIL PRESSURIZED
      X=SPRNZ+CONPR-CILHT+RTDP
      IF(CWRTI-.0001)40,40,50
C *** EXRT IS THE EXTRA HEAD NEEDED TO KEEP COIL PRESSURIZED
C *** THAT MUST BE THROTTLED IN THE RETURN LINE
C *** WHEN THERE IS NO WATER RECOVERY TURBINE
   40 EXRT=36.9-X
      EXRT=AMAX1(0.0,EXRT)
      WRTHD=0.0
      GO TO 60
   50 WRTHD=3.+33.9-X
      WRTHD=AMAX1(0.0,WRTHD)
      EXRT=0.0
   60 CONTINUE
C *** TOTAL PUMP HEAD IN FEET
      TOPHD=SPRNZ+DPTOT(1)*2.3066+WRTHD+CWTLV+SPDP+EXRT-SPRHT+RTDP
      GO TO 75
C *** FIND PUMP HEAD IN FEET WITH SURFACE CONDENSER
   70 WRTHD=0.
      TOPHD=2.3066*(DPTOT(1)+DPCON)+SPDP+RTDP
   75 CONTINUE
      RETURN
      END
```

```
      SUBROUTINE DPSEN(DTI,DL,ICLG,GT,RE,GOSW,DEN,RVIS,DP,FF)
C *** CALCULATES TUBESIDE SINGLE-PHASE PRESSURE DROP - COMMERCIAL PIPE
C *** OR DRAWN TUBING WITH FOULING
C *** PROPERTY VARIATION CORRECTION FACTOR - SIEDER + TATE
      PHI = 1.0
      IF ( ICLG - 1 )   30, 8,30
    8 VR  = 1./RVIS
      IF (RE - 2000.)   15,10,10
   10 IF (RE - 4000.)   25,20,20
   15 PHI = VR**.25
```

```
      GO TO 30
   20 PHI = VR**.14
      GO TO 30
   25 PRO = 2.0 - 0.0005*RE
      PHI = VR**.25*PRO + VR**.14*(1.-PRO)
C *** ISOTHERMAL FRICTION FACTOR
   30 CONTINUE
   35 IF (RE - 1380.)   55,55,40
   40 IF (RE - 4000.)   60,60,70
C ***       HAGEN-POISEUILLE
   55 FIS = 16./RE
      GO TO 75
   60 FIS = 0.0116
      GO TO 75
C ***       WILSON-MC.ADAMS-SELTZER
   70 FIS = .0035 + .264/RE**.42
C *** FANNING FRICTION FACTOR AND PRESSURE DROP
   75 FF  = FIS*PHI
      DP  = 0.333E-10 * DL*GT**2*FF/(DTI*DEN)
      RETURN
      END
```

```
      SUBROUTINE DPTUB
C *** CALCULATES PROCESS SIDE PRESSURE DROPS IN THE EXCHANGER
C *** OVERALL CASE
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      NQZ=1
      XP=NTP
      KCLG=1
      ZLL=DLTO
C *** CALCULATE TUBE PRESSURE DROP
   90 TB=(TT(NQZ)+TT(NQZ+1))*.5
      TC=.5*(TIN(2)+TOUT(2))
      TW=TB-(TB-TC)*UTOT*RADI/HTS
      DENT=DENLZ(NQZ)
      CALL PPVIS(TW,KCLG,VISW,VISB,OMV,OML)
      VISB=VISLZ(NQZ)
      RVIS=VISB/VISW
  130 RE=DTI*GT/(29.*VISB)
      CALL DPSEN(DTI,ZLL,KCLG.GT,RE,0.,DENT,RVIS,DPF(NQZ),FFF)
C *** CALCULATE INLET HEADER CONTRACTION
      DPTA1=1.5*GT**2/(1.2E11*DEN12(1,1))
C *** CALCULATE OUTLET HEADER EXPANSION
      DPTA3=.25*GT**2/(1.2E11*DEN12(2,1))
C *** CALCULATE RETURN HEADER LOSS
      DPTA2=1.5*GT**2/(1.2E11*DENT)
C *** TOTAL LOSSES OF HEADERS
      DPTAS=DPTA1+(XP-1.)*DPTA2+DPTA3
C *** TOTAL TUBE LOSSES
      DPTF=XP*DPF(1)
C *** TOTAL PRESSURE DROP
      DPT=DPTF+DPTAS
      DPTA=DPTAS
C *** SIZE AND CALC. PRESS. DROP IN OUTLET NOZZLE
      CALL NOZCT(DNZI,DNZ,WB(1)/ZNOZ(2),VNZ,DEN12,0.0   ,DPNZ,DBW,0.0,2)
C *** RESET TUBE SIDE PHYS.PROP. TO AVG. TEMP.
      TAV(1)=0.5*(TIN(1)+TOUT(1))
      CALL PPVIS(TAV(1),1,VIS(1),DUM1,OMV,OML)
      REA(1)=GT*DTI/(29.0*VIS(1))
      DPTOT(1)=ZBUS*(DPT+DPNZ(1)+DPNZ(2))
  430 AX=AXPP(NTP)
  440 VT=WB(1)/(AX*DEN12(1,1)*3600.)
  500 RETURN
      END
      SUBROUTINE ERORF(KER,KERR,KGO,MM)
C *** SETS PERMANENT ERRORS
      DIMENSION KERR(1)
      KX=MM+1
      KXX=MM+2
      IF (KER) 200,200,20
   20 IF (MM-1) 40,40,30
C *** IF LAST TWO ERRORS ARE SAME WITH NEW KER DO NOT STORE
   30 IF (KER-KERR(MM)) 40,32,40
   32 IF (KER-KERR(MM-1)) 40,90 ,40
   40 MM=MM+1
      IF (MM-20) 50,50,150
   50 KERR(MM)=KER
C *** MINOR ERRORS FROM 1 TO 49 - MAJOR ERRORS .GE.50 SET KGO=2
   90 IF (KER-49) 100,100,150
  100 KER=0
      GO TO 200
  150 KGO=2
  200 RETURN
      END
```

```
      SUBROUTINE ERORG (N,KERRO,KER)
      DIMENSION KERRO(1)
      IF (N-20) 10,20,20
   10 N=N+1
      KERRO(N)=KER
   20 RETURN
      END
      SUBROUTINE EXCON
C *** CALCULATES TOTAL CONDENSING AREA AND DESUPERHEATING/SUBCOOLING
C *** AREA AS REQUIRED USING OVERALL METHOD
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3SPC,ZTPD,ZD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      FSUM=0.0
      GT=WB(1)/AXAV
C *** SENSIBLE CASE CALC. START HERE
      PRAN(1)=PRALZ(1)
      CALL UOSEN(1)
      IF (KER) 550,550,590
  550 CALL MTDOV(TD,NP,NTR,1,1.0,KER,P,R,TNU1,LPMT,TMTD,F,0.0)
      IF (KER) 560,560,590
  560 QTOT  =UTOT  *ASTOT*TMTD
      FSUM=QDUT/QTOT
  590 RETURN
      END
```

```
      SUBROUTINE EXINI
C *** INITIALIZES VARIABLES USED IN COMMON WHICH MAY BE PRESET BY INPUT
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QOUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/JUMP/JAKE,TINMX,NOO2I,DTN2I,NOO1I,NFPIN,NOO2O,NOO1O
  803 FORMAT(9H   KER = ,20(I3,1H,))
      DFAN=DFANI
      ZNTT=ZNTD
C *** PRINT OUT ANY ERRORS
      IF(MM)802,802,801
  801 WRITE(NFO,803)(KERR(I),I=1,MM)
      IF(MOD(KNTRO,5).NE.0)KNTRO=KNTRO+1
  802 CONTINUE
C *** RESET ERROR VARIABLES FOR NEXT POINT.  AS SUPER IS CALLED
C *** AGAIN AND AGAIN THESE VARIABLES MUST BE RESET
      DO 810 I=1,20
  810 KERR(I)=0
      KER=0
      KGO=1
      MM=0
 1001 CONTINUE
      DO 12 J=1,2
      TIN(J) =TIND (J)
      TOUT(J)=TOUTD(J)
      DNZ(J)=DNZI(J)
   12 W(J)=WD(J)
      TD=TIN(1)-TIN(2)
      VAPP=VAPPI
      DPTOT(1)=0.0
      IF(JAKE.NE.1)GO TO 91
      ZNTR=ZTRD
      ZNTP=ZTPD
      NTP=ZNTP+0.01
      NTR=ZNTR+0.01
      ANG(1)=ANGI*PI/180.
      ANG(2)=SIN(ANG(1))
      ANG(3)=COS(ANG(1))
      PT=PTI
   91 CONTINUE
      ZMP=ZBUP*ZBYP
      TT(1)=TIN(1)
  400 CONTINUE
```

```
      RETURN
      END
      SUBROUTINE EXSTP(ZBUP,NBLD,NFAN,ZBPU,CERCT)
C
C *** THIS SUBROUTINE ESTIMATES THE COST OF ERECTING THE COOLING
C *** TOWER ON THE STRUCTURE
C
C *** INPUT VARIABLES ***
C     ZBUP  = NUMBER OF BUNDLES PER BAY
C     NBLD  = NUMBER OF BLADES PER FAN
C     NFAN  = NUMBER OF FANS PER BAY
C     ZBPU  = NUMBER OF BAYS PER UNIT
C
C *** OUTPUT VARIABLE ***
C     CERCT = ERECTION COST ($)
C
      ZBLD=NBLD
      ZFAN=NFAN
C *** ASSUME 1600 DOLLARS TO SET AND ALIGN EACH BUNDLE
      C1=1600.*ZBUP
C *** ASSUME 1120 DOLLARS TO INSTALL PLENUM
      C2=1120.
C *** ASSUME 640 DOLLARS TO INSTALL FAN AND 40 DOLLARS TO BALANCE
C *** EACH BLADE
      C3=(40.*ZBLD+640.)*ZFAN
C *** ASSUME 880 DOLLARS FOR INSTALLING RECOVERY STACK
      C4=880.*ZFAN
C *** ASSUME 320 DOLLARS FOR ELECTRICAL HOOK-UP OF FAN
      C5=320.*ZFAN
C *** ASSUME 240 DOLLARS TO TEST FAN
      C6=240.*ZFAN
C
C *** ASSUME 2.5 FACTOR FOR CONTINGENCIES
      CERCT=2.5*ZBPU*(C1+C2+C3+C4+C5+C6)
 1000 RETURN
      END
      SUBROUTINE FAN(NFAN,DFAN,NBLD,IDFAN,CFAN1,CTFAN)
C
C *** THIS SUBROUTINE CALCULATES THE COST FOR PURCHASING A FAN
C
C *** INPUT VARIABLES ***
C     DFAN  = FAN DIAMETER (FT)
C     NBLD  = NUMBER OF BLADES PER FAN
C     IDFAN = FAN TYPE IDENTIFICATION
C             1 FOR PERMANENTLY FIXED
C             2 FOR MANUAL ADJUSTABLE
C             3 FOR AUTOMATIC VARIABLE
C
C *** OUTPUT VARIABLE ***
C     CFAN1 = COST FOR ONE FAN ($)
C
      ZFAN=NFAN
      ZBLD=NBLD
      IF (IDFAN-2) 100,200,200
C
  100 CONTINUE
      GO TO 400
C     INFORMATION FOR THE COST OF FIXED-BLADES TYPE FANS NOT AVAILABLE
C     AT PRESENT TIME.
C
C
C     COST CALCULATION FOR MANUAL ADJUSTABLE OR AUTOMATIC ADJUSTABLE FAN
  200 CONTINUE
C     FOR FAN DIAMETER GREATER THAN 20 FT, THE COST IS CALCULATED BASING
C     ON THE COST OF 28 FT FAN
C
      IF (DFAN-20.0) 210,240,240
  210 CONTINUE
C     THI INFORMATION FOR COST OF FAN UNDER 20 FT IS NOT AVAILABLE NOW
C     HERE CALCULATION IS BASED ON THE EXTRAPLOTAION OF THE >20FT FANS
C
C
  240 CONTINUE
C     WHEN DFAN=28 FT, THE COST IS
      CF28=409.2*ZBLD+300.3
C
      IF (DFAN-28.0) 270,270,280
  270 CONTINUE
      CFAN1=CF28*(1.0/(1.0+0.071*(28.0-DFAN)/2.0))
      GO TO 285
C
  280 CONTINUE
      CFAN1=CF28*(1.0+0.088*(DFAN-28.0)/2.0)
C
  285 CONTINUE
      IF (IDFAN-2) 400,400,300
  300 CFAN1=CFAN1+250.0*ZBLD
C     FOR FANS WITH AUTOMATIC ADJUSTABLE BLADES, ADD EXTRA COST AT 250$
C     PER BLADE
C
  400 CONTINUE
      CTFAN=ZFAN*CFAN1
C
      RETURN
      END


      SUBROUTINE FANCON(CFMB,FTPB,BETA,KODE,HPB,KSTEP,TPS,EFF,HPA,SIZEA,
     1DENA,CFMA,FTPA,NB,VTIPA,RPMA)
      DIMENSION BLANG(9),TP(9),HP(9)
      KODE = 0
      TPS = 0.0
      HPA = 0.0
      KSTEP = 0
      BETA = 0.0
      EFF = 0.0
      J = 0
      DENB = 0.075
      VTIPB = 12000.
      SIZEB = 28.0
      INC = 4
      ISTART = 2
    4 IF(NB-8)15,5,6
    5 INC = 2
      ISTART = 6
      IB = 3
      GO TO 100
    6 IF(NB-9)15,7,8
    7 CONTINUE
      ISTART = 6
      IB = 4
      GO TO 100
    8 IF(NB-10)15,9,10
    9 IB = 5
      GO TO 100
   10 IF(NB-11)15,12,13
   12 SIZEB = 30.0
      IB = 6
      GO TO 100
   13 IF(NB-12)15,14,15
   14 IB = 7
      GO TO 100
   15 WRITE(6,16)
   16 FORMAT(31H THERE IS NO DATA FOR THIS CASE)
  100 CONTINUE
C *** FAN LAWS BELOW ALLOW US TO EXTRAPOLATE TO ANY FLOW, SIZE OR RPM
      VRATIO = VTIPA/VTIPB
      RPMB = VTIPB/(SIZEB*3.14159)
      RPMA = VTIPA/(SIZEA*3.14159)
      CFMB = ((SIZEB/SIZEA)**2)*CFMA *VRATIO
      FTPB = FTPA *(DENB/DENA)*(VRATIO**2)
      IB=IB-2
      DO 200 IX = ISTART,22,INC
      J = J + 1
      I = J
      BLANG(I) = IX
      GO TO(103,104,105,106,107),IB
  103 CALL FDPNB8(CFMB,TP(I),BLANG(I),NB,KEXDP)
      GO TO 110
  104 CALL FDPNB9(CFMB,TP(I),BLANG(I),NB,KEXDP)
      GO TO 110
  105 CALL FDPNB10(CFMB,TP(I),BLANG(I),NB,KEXDP)
      GO TO 110
  106 CALL FDPNB11(CFMB,TP(I),BLANG(I),NB,KEXDP)
      GO TO 110
  107 CALL FDPNB12(CFMB,TP(I),BLANG(I),NB,KEXDP)
  110 CONTINUE
      IF(TP(I)-1.E-9)200,200,120
  120 IF(FTPB-TP(I))130,130,160
  130 IF(KODE)150,150,140
C *** CALC BETA-THE INTERPOLATED VALUE OF BLADE ANGLE ONLY IF KODE=1
  140 BETA = ((FTPB-TP(I-1))/(TP(I)-TP(I-1)))*(BLANG(I)-BLANG(I-1)) +
     1BLANG(I-1)
      GO TO 250
C *** SET THE LOWEST VALUE OF BLADE ANGLE -INDICATES SMALLER FAN NEEDED
  150 BETA = BLANG(I)
      KSTEP = -1
      GO TO 1000
  160 KODE = 1
  200 CONTINUE
C *** AT THIS POINT AN ERROR MUST BE SET BECAUSE THE FAN CHARACTERISTICS
C     DO NOT SUIT THE SIZE UNDER DISCUSSION . STEP UP TO NEXT FAN SIZE.
      KSTEP = 1
      BETA = 22.0
      GO TO 1000
  250 CONTINUE
      IF(J-1)260,260,270
C *** J MUST BE GREATER THAN 1
  260 WRITE(6,400)
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      GO TO 1000
  270 CONTINUE
C *** FIND THE FAN HORSEPOWER WHICH SUITS THE CFMB AND BETA FOUND ABOVE
C *** CONVERT BACK TO FAN UNDER CONSIDERATION
      GO TO(303,304,305,306,307),IB
  303 CALL FHPNB8(CFMB,HP(J-1),BLANG(J-1),NB,KEXHP)
      CALL FHPNB8(CFMB,HP(J),BLANG(J),NB,KEXHP)
      GO TO 310
  304 CALL FHPNB9(CFMB,HP(J-1),BLANG(J-1),NB,KEXHP)
      CALL FHPNB9(CFMB,HP(J),BLANG(J),NB,KEXHP)
      GO TO 310
  305 CALL FHPNB10(CFMB,HP(J-1),BLANG(J-1),NB,KEXHP)
      CALL FHPNB10(CFMB,HP(J),BLANG(J),NB,KEXHP)
      GO TO 310
  306 CALL FHPNB11(CFMB,HP(J-1),BLANG(J-1),NB,KEXHP)
      CALL FHPNB11(CFMB,HP(J),BLANG(J),NB,KEXHP)
      GO TO 310
  307 CALL FHPNB12(CFMB,HP(J-1),BLANG(J-1),NB,KEXHP)
      CALL FHPNB12(CFMB,HP(J),BLANG(J),NB,KEXHP)
  310 CONTINUE
      HPB =((BETA-BLANG(J-1))/(BLANG(J)-BLANG(J-1)))*(HP(J)-HP(J-1)) +
     1HP(J-1)
C *** CONVERT BACK TO FAN UNDER CONSIDERATION
      HPA = HPB *((SIZEA/SIZEB)**2)*(DENA/DENB)*(VRATIO**3)
      EFF = (CFMB*1000.0*FTPB)/(6356.0*HPB)
C *** MAKE SOME CHECKS TO DETERMINE IF FAN IS NEAR STALL POINT
C *** FOR THE BETA BLADE ANGLE FIND IF THE DP IS LOWERED AS THE CAPACITY
C     IS LOWERED BY 10 PERCENT
      CFM = .90*CFMB
C *** IF LOWER HP THEN WE ARE ENTERING STALL REGION
      GO TO(313,314,315,316,317),IB
  313 CALL FDPNB8(CFM,TP(J),BLANG(J),NB,K)
      CALL FDPNB8(CFM,TP(J-1),BLANG(J-1),NB,K)
      GO TO 320
  314 CALL FDPNB9(CFM,TP(J),BLANG(J),NB,K)
      CALL FDPNB9(CFM,TP(J-1),BLANG(J-1),NB,K)
      GO TO 320
  315 CALL FDPNB10(CFM,TP(J),BLANG(J),NB,K)
      CALL FDPNB10(CFM,TP(J-1),BLANG(J-1),NB,K)
      GO TO 320
  316 CALL FDPNB11(CFM,TP(J),BLANG(J),NB,K)
      CALL FDPNB11(CFM,TP(J-1),BLANG(J-1),NB,K)
      GO TO 320
  317 CALL FDPNB12(CFM,TP(J),BLANG(J),NB,K)
      CALL FDPNB12(CFM,TP(J-1),BLANG(J-1),NB,K)
  320 CONTINUE
  400 FORMAT(38H  SOMETHING IS WRONG,J=1 AT THIS POINT)
      TPS=((BETA-BLANG(J-1))/(BLANG(J)-BLANG(J-1)))*(TP(J)-TP(J-1)) +
     1TP(J-1)
      IF(TPS-FTPB)550,550,1000
  550 KSTEP = -2
 1000 CONTINUE
      RETURN
      END


      SUBROUTINE FDPNB8(CFM,DP,ANGLE,NB,KEXDP)
C *** THIS SUBROUTINE CALCULATES FAN TOTAL PRESSURE DROP-GIVEN THE BLADE
C *** ANGLE AND FLOW -FOR 8 BLADES -28FT. FAN
      KEXDP = 0
      IF(NB-6)7,7,8
    7 CONTINUE
    8 IF(NB-8)9,9,11
   11 GO TO 3000
    9 CONTINUE
 2001 IF(ANGLE-6.01)2002,2002,2007
 2002 IF(CFM-840.)2003,2003,2004
 2003 DP =-8.0294E-4 *CFM +1.0744
      GO TO 3000
 2004 IF(CFM-1045.)2005,2005,2006
 2005 DP =-9.512E-4 *CFM +1.199
 2006 KEXDP = 6
C *** EQUATION GOOD FROM 840 TO 1045
      GO TO 3000
 2007 IF(ANGLE-8.01)2008,2008,2013
 2008 IF(CFM -830.)2009,2009,2010
 2009 DP =-7.838E-4 *CFM +1.1905
      GO TO 3000
 2010 IF(CFM -1172.)2011,2011,2012
 2011 DP = -8.246E-4 *CFM +1.2244
C *** EQUATION GOOD FROM 830 TO 1172
 2012 KEXDP = 8
      GO TO 3000
 2013 IF(ANGLE-10.01)2014,2014,2019
 2014 IF(CFM -1090.)2015,2015,2016
 2015 DP =-7.672E-4 *CFM +1.3163
      GO TO 3000
 2016 IF(CFM -1280.)2017,2017,2018
 2017 DP =-9.474E-4 *CFM +1.513
 2018 KEXDP =10
C *** EQUATION GOOD FROM 1090 TO 1280
      GO TO 3000
 2019 IF(ANGLE-12.01)2020,2020,2027
 2020 IF(CFM -90G.0)2021,2021,2022
 2021 DP =-5.1E-4 *CFM + 1.237
      GO TO 3000
 2022 IF(CFM -1130.)2023,2023,2024
 2023 DP = -7.74E-4 *CFM +1.4745
      GO TO 3000
 2024 IF(CFM -1400.)2025,2025,2026
 2025 DP =-8.89E-4 *CFM + 1.6044
 2026 KEXDP = 12
C *** EQUATION GOOD FROM 1130 TO 1400
      GO TO 3000
 2027 IF(ANGLE- 14.01)2028,2028,2039
 2028 IF(CFM -800.)2029,2029,2030
 2029 DP =-2.033E-4*CFM +1.1017
      GO TO 3000
 2030 IF(CFM-900.)2031,2031,2032
 2031 DP =-6.4E-4*CFM +1.451
      GO TO 3000
 2032 IF(CFM-1030.)2033,2033,2034
 2033 DP =-4.23E-4*CFM +1.2558
      GO TO 3000
 2034 IF(CFM-1200.)2035,2035,2036
 2035 DP =-7.06E-4 *CFM +1.5471
      GO TO 3000
 2036 IF(CFM -1540.)2037,2037,2038
 2037 DP =-7.647E-4 *CFM +1.61765
 2038 KEXDP = 14
C *** EQUATION GOOD FROM 1200 TO 1500
      GO TO 3000
 2039 IF(ANGLE -16.01)2040,2040,2049
 2040 IF(CFM-1110.)2041,2041,2042
 2041 DP =-3.9E-4 *CFM + 1.2917
      GO TO 3000
 2042 IF(CFM - 1250.)2043,2043,2044
 2043 DP =-5.714E-4 *CFM +1.4943
      GO TO 3000
 2044 IF(CFM -1430.)2045,2045,2046
 2045 DP =-7.22E-4*CFM +1.6828
      GO TO 3000
 2046 IF(CFM-1625.)2047,2047,2048
 2047 DP =-8.21E-4 *CFM + 1.8233
 2048 KEXDP = 16
C *** EQUATION GOOD FROM 1430 TO 1625
      GO TO 3000
 2049 IF(ANGLE-18.01)2050,2050,2069
 2050 IF(CFM -600.)2051,2051,2052
 2051 DP =-0.001*CFM +1.02
      GO TO 3000
 2052 IF(CFM-750.)2053,2053,2054
 2053 DP = 0.96
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      GO TO 3000                                                        22560
 2054 IF(CFM-900.)2055,2055,2056                                        22570
 2055 DP=0.00012*CFM +0.87                                              22580
      GO TO 3000                                                        22590
 2056 IF(CFM -1000.)2057,2057,2058                                      22600
 2057 DP = 0.978                                                        22610
      GO TO 3000                                                        22620
 2058 IF(CFM-1090.)2059,2059,2060                                       22630
 2059 DP =-3.11E-4 *CFM +1.2891                                         22640
      GO TO 3000                                                        22650
 2060 IF(CFM -1200.)2061,2061,2062                                      22660
 2061 DP =-3.64E-4 *CFM + 1.3468                                        22670
      GO TO 3000                                                        22680
 2062 IF(CFM-1330.)2063,2063,2064                                       22690
 2063 DP =-5.39E-4 *CFM +1.55621                                        22700
      GO TO 3000                                                        22710
 2064 IF(CFM - 1500.)2065,2065,2066                                     22720
 2065 DP=-7.06E-4 * CFM +1.779                                          22730
      GO TO 3000                                                        22740
 2066 IF(CFM-1710.)2067,2067,2068                                       22750
 2067 DP=-8.10E-4 *CFM +1.9353                                          22760
 2068 KEXDP =18                                                         22770
C *** EQUATION GOOD FROM 1500 TO 1710                                    22780
      GO TO 3000                                                        22790
 2069 IF(ANGLE-20.01)2070,2070,2079                                     22800
 2070 IF(CFM-1370.)2071,2071,2072                                       22810
 2071 DP=-3.33E-4 *CFM +1.3667                                          22820
      GO TO 3000                                                        22830
 2072 IF(CFM-1470.)2073,2073,2074                                       22840
 2073 DP=-5E-4 *CFM +1.595                                              22850
      GO TO 3000                                                        22860
 2074 IF(CFM-1610.)2075,2075,2076                                       22870
 2075 DP =-7.143E-4 *CFM + 1.91                                         22880
      GO TO 3000                                                        22890
 2076 IF(CFM-1770.)2077,2077,2078                                       22900
 2077 DP =-1.25E-3 *CFM + 2.7725                                        22910
 2078 KEXDP = 20                                                        22920
C *** EQUATION GOOD FROM 1610 TO 1770                                    22930
      GO TO 3000                                                        22940
 2079 IF(ANGLE-22.01)2080,2080,3000                                     22950
 2080 IF(CFM-600.)2081,2081,2082                                        22960
 2081 DP = -0.00015*CFM +1.05                                           22970
      GO TO 3000                                                        22980
 2082 IF(CFM-850.)2083,2083,2084                                        22990
 2083 DP = 0.96                                                         23000
      GO TO 3000                                                        23010
 2084 IF(CFM -1100.)2085,2085,2086                                      23020
 2085 DP =0.00016*CFM +0.824                                            23030
      GO TO 3000                                                        23040
 2086 IF(CFM -1250.)2087,2087,2088                                      23050
 2087 DP =0.000067* CFM + 0.9267
      GO TO 3000
 2088 IF(CFM -1350.)2089,2089,2090
 2089 DP=-0.0001*CFM + 1.135
      GO TO 3000
 2090 IF(CFM -1450.)2091,2091,2092
 2091 DP=-0.0002*CFM + 1.27
      GO TO 3000
 2092 IF(CFM -1530,)2093,2093,2094
 2093 DP =-0.0005 *CFM + 1.705
      GO TO 3000
 2094 IF(CFM -1650.)2095,2095,2096
 2095 DP = -0.00065 *CFM + 1.9345
      GO TO 3000
 2096 IF(CFM -1770.)2097,2097,2098
 2097 DP = -0.00085*CFM +2.2645
      GO TO 3000
C *** EQUATION GOOD FROM 1650 TO 1770
 2098 KEXDP =22
 3000 DP =AMAX1(0.0,DP)
      RETURN
      END
```

```
      SUBROUTINE FDPNB9(CFM,DP,ANGLE,NB,KEXDP)
C *** THIS SUBROUTINE CALCULATES FAN TOTAL PRESSURE DROP-GIVEN THE BLADE
C *** ANGLE AND FLOW-CFM -FOR 9 BLADES -12000 FPM-136 RPM,28FT. FAN
C *** DP - IS THE CORRECTED TOTAL PRESSURE DROP,INCH OF H2O
C *** CFM - IS THE ACTUAL FLOW RATE IN 10E3 CUBIC FOOT PER MINUTE
C *** HP - CURVE HP WHICH MUST BE CORRECTED FOR DENSITY RATIO,THE EFFECT
C *** OF ALTITUDE,AND SPEED FACTOR. CURVE IS BASED ON 12000 FT/MIN TIP
C *** SPEED
      KEXDP=0
      IF(ANGLE-6.01)35,35,80
   35 IF(CFM-750.)40,40,45
   40 DP=-8.E-4*CFM+1.125
      GO TO 600
   45 IF(CFM-900.)50,50,55
   50 DP=-9.66666E-4*CFM+1.25
      GO TO 600
   55 IF(CFM-1050.)60,60,58
   58 KEXDP=6
   60 DP=-1.16666E-3*CFM+1.43
```

```
C *** EQUATION GOOD FROM 900 TO 1050
      GO TO 600
   80 IF(ANGLE-10.01)85,85,170
   85 IF(CFM-1040)90,90,95
   90 DP=-8.38888E-4*CFM+1.44944
      GO TO 600
   95 IF(CFM-1180.)100,100,105
  100 DP=-1.01428E-3*CFM+1.63185
      GO TO 600
  105 IF(CFM-1285.)110,110,108
  108 KEXDP=10
  110 DP=-1.20952E-3*CFM+1.86224
C *** EQUATION GOOD FROM 1180 TO 1285
      GO TO 600
  170 IF(ANGLE-14.01)175,175,260
  175 IF(CFM-730.)180,180,185
  180 DP=-8.69565E-5*CFM+1.09347
      GO TO 600
  185 IF(CFM-900.)190,190,195
  190 DP=-4.11765E-4*CFM+1.33059
      GO TO 600
  195 IF(CFM-1150.)200,200[illegible]5
  200 DP=-6.8E-4*CFM+1.57[illegible]
      GO TO 600
  205 IF(CFM-1558.)210,210,208
  208 KEXDP=14
  210 DP=-8.45588E-4*CFM+1.76242
C *** EQUATION GOOD FROM 1150 TO 1558
      GO TO 600
  260 IF(ANGLE-18.01)325,325,390
  325 IF(CFM-740.)330,330,335
  330 DP=1.05
      GO TO 600
  335 IF(CFM-930.)340,340,345
  340 DP=1.31579E-4*CFM+0.95263
      GO TO 600
  345 IF(CFM-1010.)350,350,355
  350 DP=-6.25E-5*CFM+1.13312
      GO TO 600
  355 IF(CFM-1190.)360,360,365
  360 DP=-3.38888E-4*CFM+1.41228
      GO TO 600
  365 IF(CFM-1370.)370,370,375
  370 DP=-6.33333E-4*CFM+1.76266
      GO TO 600
  375 IF(CFM-1745.)380,380,378
  378 KEXDP=18
  380 DP=-8.66666E-4*CFM+2.08233
C *** EQUATION GOOD FROM 1370 TO 1745
      GO TO 600
  390 IF(ANGLE-22.01)410,410,600
  410 IF(CFM-840.)420,420,425
  420 DP=-4.41176E-5*CFM+1.07206
      GO TO 600
  425 IF(CFM-1170.)430,430,435
  430 DP=2.12121E-4*CFM+0.85682
      GO TO 600
  435 IF(CFM-1360.)440,440,445
  440 DP=-2.63158E-5*CFM+1.13579
      GO TO 600
  445 IF(CFM-1490.)450,450,455
  450 DP=-3.84615E-4*CFM+1.62307
      GO TO 600
  455 IF(CFM-1630.)460,460,465
  460 DP=-6.78571E-4*CFM+2.06107
      GO TO 600
  465 IF(CFM-1770.)470,470,468
  468 KEXDP=22
  470 DP=-9.28571E-4*CFM+2.46857
C *** EQUATION GOOD FROM 1630 TO 1770
C *** NEVER ALLOW THE PRESSURE DROP TO BE LESS THAN ZERO
  600 DP=AMAX1(0.0,DP)
      RETURN
      END


      SUBROUTINE FDPNB10(CFM,DP,ANGLE,NB,KEXDP)
C *** THIS SUBROUTINE CALCULATES FAN TOTAL PRESSURE DROP-GIVEN THE BLADE
C *** ANGLE AND FLOW -CFM-FOR 10 BLADES -12000FPM -136RPM -28FT. FAN
      KEXDP=0
      IF(ANGLE-2.01)15,15,100
   15 IF(CFM-700.)20,20,25
   20 DP=-1.125E-3*CFM+1.1025
      GO TO 600
   25 IF(CFM-840.)30,30,28
   28 KEXDP=2
   30 DP=-1.39285E-3*CFM+1.2899
C *** EQUATION GOOD FROM 700 TO 840
      GO TO 600
  100 IF(ANGLE-6.01)105,105,200
  105 IF(CFM-800.)110,110,115
  110 DP=-9.44444E-4*CFM+1.28055
      GO TO 600
  115 IF(CFM-960.)120,120,125
  120 DP=-1.09375E-3*CFM+1.4
      GO TO 600
  125 IF(CFM-1070.)130,130,128
  128 KEXDP=6
  130 DP=-1.36363E-3*CFM+1.65909
C *** EQUATION GOOD FROM 960 TO 1070
      GO TO 600
  200 IF(ANGLE-10.01)205,205,300
  205 IF(CFM-730.)210,210,215
  210 DP=-6.25E-4*CFM+1.37625
      GO TO 600
  215 IF(CFM-920.)220,220,225
  220 DP=-8.94736E-4*CFM+1.57315
      GO TO 600
  225 IF(CFM-1310.)230,230,228
  228 KEXDP=10
  230 DP=-1.12820E-3*CFM+1.78795
C *** EQUATION GOOD FROM 920 TO 1310
      GO TO 600
  300 IF(ANGLE-14.01)305,305,400
  305 IF(CFM-770.)310,310,315
  310 DP=-2.22222E-4*CFM+1.26111
      GO TO 600
  315 IF(CFM-970.)320,320,325
  320 DP=-4.5E-4*CFM+1.4365
      GO TO 600
  325 IF(CFM-1200.)330,330,335
  330 DP=-7.82608E-4*CFM+1.75913
      GO TO 600
  335 IF(CFM-1580.)340,340,338
  338 KEXDP=14
  340 DP=-9.73684E-4*CFM+1.98842
C *** EQUATION GOOD FROM 1200 TO 1580
      GO TO 600
  400 IF(ANGLE-18.01)405,405,500
  405 IF(CFM-700.)410,410,415
  410 DP=-6.0E-5*CFM+1.2
      GO TO 600
  415 IF(CFM-950.)420,420,425
  420 DP=1.2E-5*CFM+1.1496
      GO TO 600
  425 IF(CFM-1100.)430,430,435
  430 DP=-1.53333E-4*CFM+1.30666
      GO TO 600
  435 IF(CFM-1250.)440,440,445
  440 DP=-4.53333E-4*CFM+1.63666
      GO TO 600
  445 IF(CFM-1440.)450,450,455
  450 DP=-7.36842E-4*CFM+1.99105
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      GO TO 600
  455 IF(CFM-1600.)460,460,465
  460 DP=-1.0E-3*CFM+2.37
      GO TO 600
  465 IF(CFM-1770.)470,470,468
  468 KEXDP=18
  470 DP=-1.11764E-3*CFM+2.55823
C *** EQUATION GOOD FROM 1600 TO 1770
      GO TO 600
  500 IF(ANGLE-22.01)505,505,600
  505 IF(CFM-800.)510,510,515
  510 DP=-8.33333E-5*CFM+1.19666
      GO TO 600
  515 IF(CFM-1100.)520,520,525
  520 DP=2.33333E-4*CFM+0.94333
      GO TO 600
  525 IF(CFM-1300.)530,530,535
  530 DP=2.5E-5*CFM+1.1725
      GO TO 600
  535 IF(CFM-1420.)540,540,545
  540 DP=-2.25E-4*CFM+1.4975
      GO TO 600
  545 IF(CFM-1570.)550,550,555
  550 DP=-6.2E-4*CFM+2.0584
      GO TO 600
  555 IF(CFM-1770.)560,560,558
  558 KEXDP=22
  560 DP=-9.25E-4*CFM+2.53725
C *** EQUATION GOOD FROM 1570 TO 1770
  600 DP=AMAX1(0.0,DP)
      RETURN
      END
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      SUBROUTINE FDPNB11(CFM,DP,ANGLE,NB,KEXDP)
C *** THIS SUBROUTINE CALCULATES FAN TOTAL PRESSURE DROP-GIVEN THE BLADE
C *** ANGLE AND FLOW-CFM-FOR 11BLADES -12000FPM -127RPM -30FT. FAN
      KEXDP=0
      IF(ANGLE-2.01)15,15,100
   15 IF(CFM-800.)20,20,25
   20 DP=-8.5E-4*CFM+.95
      GO TO 600
   25 IF(CFM-955.)30,30,28
   28 KEXDP=2
   30 DP=-9.67745E-4*CFM+1.04419
C *** EQUATION GOOD FROM 800 TO 955
      GO TO 600
  100 IF(ANGLE-6.01)105,105,200
  105 IF(CFM-1280.)110,110,108
  108 KEXDP=6
  110 DP=-7.72058E-4*CFM+1.22823
C *** EQUATION GOOD FROM 600 TO 1280
      GO TO 600
  200 IF(ANGLE-10.01)205,205,300
  205 IF(CFM-800.)210,210,215
  210 DP=-4.5E-4*CFM+1.25
      GO TO 600
  215 IF(CFM-1300.)220,220,225
  220 DP=-6.6E-4*CFM+1.418
      GO TO 600
  225 IF(CFM-1560.)230,230,228
  228 KEXDP=10
  230 DP=-8.07692E-4*CFM+1.61
C *** EQUATION GOOD FROM 1300 TO 1560
      GO TO 600
  300 IF(ANGLE-14.01)305,305,400
  305 IF(CFM-900.)310,310,315
  310 DP=-5.E-5*CFM+1.1
      GO TO 600
  315 IF(CFM-1100.)320,320,325
  320 DP=-3.25E-4*CFM+1.3475
      GO TO 600
  325 IF(CFM-1300.)330,330,335
  330 DP=-5.5E-4*CFM+1.595
      GO TO 600
  335 IF(CFM-1870.)340,340,338
  338 KEXDP=14  14
  340 DP=-6.0526E-4*CFM+1.66684
C *** EQUATION GOOD FROM 1300 TO 1870
      GO TO 600
  400 IF(ANGLE-18.01)405,405,500
  405 IF(CFM-1300.)410,410,415
  410 DP=1.42857E-5*CFM+1.09
      GO TO 600
  415 IF(CFM-1450.)420,420,425
  420 DP=-2.33333E-4*CFM+1.41333
      GO TO 600
  425 IF(CFM-1600.)430,430,435
  430 DP=-4.E-4*CFM+1.655
      GO TO 600
  435 IF(CFM-1870.)440,440,438
  438 KEXDP=18
  440 DP=-5.E-4*CFM+1.815
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C *** EQUATION GOOD FROM 1600 TO 1870
      GO TO 600
  500 IF(ANGLE-22.01)505,505,600
  505 IF(CFM-1000.)510,510,515
  510 DP=1.75E-4*CFM+.935
      GO TO 600
  515 IF(CFM-1400.)520,520,525
  520 DP=1.25E-4*CFM+.985
      GO TO 600
  525 IF(CFM-1600.)530,530,535
  530 DP=-5.E-5*CFM+1.23
      GO TO 600
  535 IF(CFM-1870.)540,540,538
  538 KEXDP=22
  540 DP=-2.96296E-4*CFM+1.62407
C *** EQUATION GOOD FROM 1600 TO 1870
  600 DP=AMAX1(.0,DP)
      RETURN
      END


      SUBROUTINE FDPNB12(CFM,DP,ANGLE,NB,KEXDP)
C *** THIS SUBROUTINE CALCULATES FAN TOTAL PRESSURE DROP-GIVEN THE BLADE
C *** ANGLE AND FLOW -CFM-FOR 12 BLADES -12000FPM -136RPM -28FT. FAN
      KEXDP=0
      IF(ANGLE-2.01)35,35,100
   35 IF(CFM-720.)40,40,45
   40 DP=-1.31818E-3*CFM+1.29909
      GO TO 600
   45 IF(CFM-860.)50,50,48
   48 KEXDP=2
   50 DP=-1.60714E-3*CFM+1.50714
C *** EQUATION GOOD FROM 720 TO 860
      GO TO 600
  100 IF(ANGLE-6.01)105,105,200
  105 IF(CFM-900.)110,110,115
  110 DP=-1.14285E-3*CFM+1.54357
      GO TO 600
  115 IF(CFM-1000.)120,120,125
  120 DP=-1.45E-3*CFM+1.82
      GO TO 600
  125 IF(CFM-1095.)130,130,128
  128 KEXDP=6
  130 DP=-1.57894E-3*CFM+1.94894
C *** EQUATION GOOD FROM 1000 TO 1095
      GO TO 600
  200 IF(ANGLE-10.01)205,205,300
  205 IF(CFM-750.)210,210,215
  210 DP=-7.5E-4*CFM+1.6175
      GO TO 600
  215 IF(CFM-850.)220,220,225
  220 DP=-9.5E-4*CFM+1.7675
      GO TO 600
  225 IF(CFM-1000.)230,230,235
  230 DP=-1.2E-3*CFM+1.98
      GO TO 600
  235 IF(CFM-1340.)240,240,238
  238 KEXDP=10
  240 DP=-1.32353E-3*CFM+2.10353
C *** EQUATION GOOD FROM 1000 TO 1340
      GO TO 600
  300 IF(ANGLE-14.01)305,305,400
  305 IF(CFM-750.)310,310,315
  310 DP=-2.4E-4*CFM+1.45
      GO TO 600
  315 IF(CFM-940.)320,320,325
  320 DP=-5.26315E-4*CFM+1.66473
      GO TO 600
  325 IF(CFM-1100.)330,330,335
  330 DP=-8.125E-4*CFM+1.93375
      GO TO 600
  335 IF(CFM-1300.)340,340,345
  340 DP=-1.E-3*CFM+2.14
      GO TO 600
  345 IF(CFM-1630.)350,350,348
  348 KEXDP=14
  350 DP=-1.0909E-3*CFM+2.25818
C *** EQUATION GOOD FROM 1300 TO 1630
      GO TO 600
  400 IF(ANGLE-18.01)405,405,500
  405 IF(CFM-650.)410,410,415
  410 DP=-1.33333E-4*CFM+1.42666
      GO TO 600
  415 IF(CFM-800.)420,420,425
  420 DP=1.03333E-4*CFM+1.27283
      GO TO 600
  425 IF(CFM-1000.)430,430,435
  430 DP=-7.75E-5*CFM+1.4175
      GO TO 600
  435 IF(CFM-1150.)440,440,445
  440 DP=-3.33333E-4*CFM+1.67333
      GO TO 600
  445 IF(CFM-1300.)450,450,455
  450 DP=-6.66666E-4*CFM+2.05666
      GO TO 600
  455 IF(CFM-1500.)460,460,465
  460 DP=-9.5E-4*CFM+2.425
      GO TO 600
  465 IF(CFM-1760.)470,470,468
  468 KEXDP=18
  470 DP=-1.15384E-3*CFM+2.73076
C *** EQUATION GOOD FROM 1500 TO 1760
      GO TO 600
  500 IF(ANGLE-22.01)505,505,600
  505 IF(CFM-950.)510,510,515
  510 DP=1.33
      GO TO 600
  515 IF(CFM-1240.)520,520,525
  520 DP=2.41379E-4*CFM+1.10068
      GO TO 600
  525 IF(CFM-1350.)530,530,535
  530 DP=-9.0909E-5*CFM+1.51272
      GO TO 600
  535 IF(CFM-1460.)540,540,545
  540 DP=-4.54545E-4*CFM+2.00363
      GO TO 600
  545 IF(CFM-1600.)550,550,555
  550 DP=-7.8571E-4*CFM+2.48714
      GO TO 600
  555 IF(CFM-1770.)560,560,558
  558 KEXDP=22
  560 DP=-1.11764E-3*CFM+3.01823
C *** EQUATION GOOD FROM 1600 TO 1770
  600 DP=AMAX1(0.0,DP)
      RETURN
      END



      SUBROUTINE FHPNB8(CFM,HP,ANGLE,NB,KEXHP)
C *** THIS SUBROUTINE CALCULATES FAN HORSPOWER-GIVEN THE BLADE ANGLE
C *** AND FLOW-CFM -FOR 8 BLADES ,28FT. FAN
      KEXHP = 0
      IF(ANGLE-6.01)1001,1001,1010
 1001 IF(CFM -650.)1002,1002,1003
 1002 HP = -0.00667*CFM +82.335
      GO TO 3000
 1003 IF(CFM -790.)1004,1004,1005
 1004 HP =-0.05714* CFM +115.14
      GO TO 3000
 1005 IF(CFM - 940.)1006,1006,1007
 1006 HP =-0.08* CFM + 133.2
      GO TO 3000
 1007 IF(CFM -1150.)1008,1008,1009
 1008 HP = -0.0619* CFM +116.19
 1009 KEXHP =6
C *** EQUATION GOOD FROM 940 TO 1150
      GO TO 3000
 1010 IF(ANGLE -8.01)1011,1011,1020
 1011 IF(CFM -800.)1012,1012,1013
 1012 HP = 90.0
      GO TO 3000
 1013 IF(CFM - 940.)1014,1014,1015
 1014 HP = -0.0357 *CFM + 118.57
      GO TO 3000
 1015 IF(CFM -1070.)1016,1016,1017
 1016 HP =-0.0769* CFM +157.31
      GO TO 3000
 1017 IF(CFM -1170.)1018,1018,1019
 1018 HP =-0.125 *CFM +208.75
 1019 KEXHP = 8
C *** EQUATION GOOD FROM 1070 TO 1170
      GO TO 3000
 1020 IF(ANGLE -10.01)1021,1021,1034
 1021 IF(CFM -740.)1022,1022,1023
 1022 HP =0.02632 *CFM + 90.53
      GO TO 3000
 1023 IF(CFM -850.)1024,1024,1025
 1024 HP = 110.0
      GO TO 3000
 1025 IF(CFM -950.)1026,1026,1027
 1026 HP =-0.02 *CFM + 127.0
      GO TO 3000
 1027 IF(CFM -1100.)1028,1028,1029
 1028 HP =-0.05333 *CFM + 158.67
      GO TO 3000
 1029 IF(CFM -1200.)1030,1030,1031
 1030 HP = -0.1 *CFM +210.0
      GO TO 3000
 1031 IF(CFM -1280.)1032,1032,1033
 1032 HP =-0.1625 *CFM + 285.
C *** EQUATION GOOD FROM 1200 TO 1280
 1033 KEXHP = 10
      GO TO 3000
 1034 IF(ANGLE-12.01)1035,1035,1046
 1035 IF(CFM -910.)1036,1036,1037
 1036 HP =0.04167*CFM +97.083
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      GO TO 3000
 1037 IF(CFM -1000.)1038,1038,1039
 1038 HP =135.0
      GO TO 3000
 1039 IF(CFM -1130.)1040,1040,1041
 1040 HP =-0.03846*CFM +173.46
      GO TO 3000
 1041 IF(CFM -1260.)1042,1042,1043
 1042 HP =-0.07692*CFM + 216.9
      GO TO 3000
 1043 IF(CFM-1400.)1044,1044,1045
 1044 HP =-0.125 *CFM + 277.5
C *** EQUATION GOOD FROM 1260 TO 1400
 1045 KEXHP = 12
      GO TO 3000
 1046 IF(ANGLE-14.01)1047,1047,1060
 1047 IF(CFM-900.)1048,1048,1049
 1048 HP =0.07069*CFM + 93.88
      GO TO 3000
 1049 IF(CFM-980.)1050,1050,1051
 1050 HP =0.03125 *CFM +129.38
      GO TO 3000
 1051 IF(CFM -1110.)1052,1052,1053
 1052 HP =160.0
      GO TO 3000
 1053 IF(CFM -1250.)1054,1054,1055
 1054 HP = -0.05*CFM + 215.5
      GO TO 3000
 1055 IF(CFM -1350.)1056,1056,1057
 1056 HP =-0.08*CFM + 253.
      GO TO 3000
 1057 IF(CFM -1530.)1058,1058,1059
 1058 HP =-0.09722 *CFM + 276.25
C *** EQUATION GOOD FROM 1350 TO 1530
 1059 KEXHP = 14
      GO TO 3000
 1060 IF(ANGLE -16.01)1061,1061,1072
 1061 IF(CFM -1100.)1062,1062,1063
 1062 HP =0.059375*CFM + 119.69
      GO TO 3000
 1063 IF(CFM-1180.)1064,1064,1065
 1064 HP = 185.0
      GO TO 3000
 1065 IF(CFM -1290.)1066,1066,1067
 1066 HP =-0.04545*CFM +238.64
      GO TO 3000
 1067 IF(CFM -1400.)1068,1068,1069
 1068 HP =-0.06818*CFM + 267.96
      GO TO 3000
 1069 IF(CFM -1600.)1070,1070,1071
 1070 HP =-0.0975 *CFM +309.
C *** EQUATION GOOD FROM 1400 TO 1600
 1071 KEXHP = 16
      GO TO 3000
 1072 IF(ANGLE-18.01)1073,1073,1086
 1073 IF(CFM -900.)1074,1074,1075
 1074 HP =0.065*CFM +136.5
      GO TO 3000
 1075 IF(CFM -1190.)1076,1076,1077
 1076 HP =0.0517 *CFM + 148.45
      GO TO 3000
 1077 IF(CFM -1270.)1078,1078,1079
 1078 HP = 210.0
      GO TO 3000
 1079 IF(CFM -1370.)1080,1080,1081
 1080 HP =-0.025 *CFM + 241.75
      GO TO 3000
 1081 IF(CFM - 1500.)1082,1082,1083
 1082 HP =-0.05769*CFM +286.54
      GO TO 3000
 1083 IF(CFM -1700.)1084,1084,1085
 1084 HP =-0.085*CFM + 327.5
C *** EQUATION GOOD FROM 1500 TO 1700
 1085 KEXHP =18
      GO TO 3000
 1086 IF(ANGLE - 20.01)1087,1087,1098
 1087 IF(CFM -1450.)1088,1088,1089
 1088 HP = 0.04444 *CFM + 173.06
      GO TO 3000
 1089 IF(CFM -1500.)1090,1090,1091
 1090 HP = 237.5
      GO TO 3000
 1091 IF(CFM -1600.)1092,1092,1093
 1092 HP = -0.025 *CFM +275.
      GO TO 3000
 1093 IF(CFM -1680.)1094,1094,1095
 1094 HP = -0.0625 *CFM + 335.
      GO TO 3000
 1095 IF(CFM - 1740.)1096,1096,1097
 1096 HP = -0.1 * CFM + 398
C *** EQUATION GOOD FROM 1680 TO 1740
      GO TO 3000
 1097 KEXHP =20
 1098 IF(ANGLE-22.01)1099,1099,3000
 1099 IF(CFM -1000.)2000,2000,2001
 2000 HP =0.024 *CFM +208.
      GO TO 3000
 2001 IF(CFM -1510.)2002,2002,2003
 2002 HP = 0.0745 *CFM + 157.50
      GO TO 3000
 2003 IF(CFM -1650.)2004,2004,2005
 2004 HP = 270.0
      GO TO 3000
 2005 IF(CFM -1770.)2006,2006,2007
 2006 HP =-0.054167*CFM + 359.4
C *** EQUATION GOOD FROM 1650 TO 1770
      GO TO 3000
 2007 KEXHP =22
C *** NEVER ALLOW THE HP TO BE LESS THAN ZERO
 3000 HP = AMAX1(0.0,HP)
      RETURN
      END


      SUBROUTINE FHPNB9(CFM,HP,ANGLE,NB,KEXHP)
C *** THIS SUBROUTINE CALCULATES FAN HORSEPOWER-GIVEN THE BLADE ANGLE
C *** AND FLOW-CFM -FOR 9 BLADES,12000 FPM- 136 RPM,28FT. FAN
C *** DP - IS THE CORRECTED TOTAL PRESSURE DROP,INCH OF H2O
C *** CFM - IS THE ACTUAL FLOW RATE IN 10E3 CUBIC FOOT PER MINUTE
C *** HP-CURVE HP WHICH MUST BE CORRECTED FOR DENSITY RATIO,THE EFFECT
C *** OF ALTITUDE,AND SPEED FACTOR. CURVE IS BASED ON 12000 FT/MIN TIP
C *** SPEED
      KEXHP=0
      IF(ANGLE-6.01)35,35,100
   35 IF(CFM-680.)40,40,45
   40 HP=1.66666E-2*CFM+78.66666
      GO TO 600
   45 IF(CFM-800.)50,50,55
   50 HP=-4.16666E-2*CFM+118.33328
      GO TO 600
   55 IF(CFM-940.)60,60,65
   60 HP=-7.85714E-2*CFM+147.85711
      GO TO 600
   65 IF(CFM-1050.)70,70,68
   68 KEXHP=6
   70 HP=-1.72727E-1*CFM+236.36335
C *** EQUATION GOOD FROM 940 TO 1050
      GO TO 600
  100 IF(ANGLE-10.01)105,105,200
  105 IF(CFM-710.)110,110,115
  110 HP=4.28571E-2*CFM+94.57143
      GO TO 600
  115 IF(CFM-880.)120,120,125
  120 HP=5.88235E-3*CFM+120.82352
      GO TO 600
  125 IF(CFM-1020.)130,130,135
  130 HP=-3.57142E-2*CFM+157.42848
      GO TO 600
  135 IF(CFM-1170.)140,140,145
  140 HP=-1.26666E-1*CFM+250.2
      GO TO 600
  145 IF(CFM-1285.)150,150,148
  148 KEXHP=10
  150 HP=-1.91304E-1*CFM+325.82608
C *** EQUATION GOOD FROM 1170 TO 1285
      GO TO 600
  200 IF(ANGLE-14.01)205,205,300
  205 IF(CFM-770.)210,210,215
  210 HP=8.88888E-2*CFM+105.55555
      GO TO 600
  215 IF(CFM-940.)220,220,225
  220 HP=5.2941E-2*CFM+133.23529
      GO TO 600
  225 IF(CFM-1080.)230,230,235
  230 HP=7.14285E-3*CFM+176.28571
      GO TO 600
  235 IF(CFM-1230.)240,240,245
  240 HP=-4.66666E-2*CFM+234.4
      GO TO 600
  245 IF(CFM-1380.)250,250,255
  250 HP=-8.66666E-2*CFM+283.6
      GO TO 600
  255 IF(CFM-1565.)260,260,258
  258 KEXHP=14
  260 HP=-1.56756E-1*CFM+380.32432
C *** EQUATION GOOD FROM 1380 TO 1565
      GO TO 600
  300 IF(ANGLE-18.01)305,305,400
  305 IF(CFM-850.)310,310,315
  310 HP=8.28571E-2*CFM+172.57143
      GO TO 600
  315 IF(CFM-1050.)320,320,325
  320 HP=5.5E-2*CFM+196.25
      GO TO 600
  325 IF(CFM-1200.)330,330,335
  330 HP=6.66666E-3*CFM+247.
      GO TO 600
  335 IF(CFM-1370.)340,340,345
  340 HP=-5.29411E-2*CFM+318.52941
      GO TO 600
  345 IF(CFM-1530.)350,350,355
  350 HP=-1.125E-1*CFM+400.125
      GO TO 600
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 355 IF(CFM-1770.)360,360,358
 358 KEXHP=18
 360 HP=-1.45833E-1*CFM+451.12499
C *** EQUATION GOOD FROM 1530 TO 1770
     GO TO 600
 400 IF(ANGLE-22.01)405,405,600
 405 IF(CFM-1105.)410,410,415
 410 HP=5.78512E-2*CFM+236.07438
     GO TO 600
 415 IF(CFM-1400.)420,420,425
 420 HP=2.03389E-2*CFM+277.52542
     GO TO 600
 425 IF(CFM-1650.)430,430,435
 430 HP=-2.4E-2*CFM+339.6
     GO TO 600
 435 IF(CFM-1770.)440,440,438
 438 KEXHP=22
 440 HP=-1.E-1*CFM+465.
C *** EQUATION GOOD FROM 1650 TO 1770
 600 HP=AMAX1(0.0,HP)
     RETURN
     END




     SUBROUTINE FHPNB10(CFM,HP,ANGLE,NB,KEXHP)
C *** THIS SUBROUTINE CALCULATES FAN TOTAL HORSPOWER -GIVEN THE BLADE
C *** ANGLE AND FLOW -CFM-FOR 10 BLADES -12000FPM -136RPM -28FT. FAN
     KEXHP=0
     IF(ANGLE-2.01)25,25,100
  25 IF(CFM-650.)30,30,35
  30 HP=-4.66666E-2*CFM+78.33333
     GO TO 600
  35 IF(CFM-830.)40,40,38
  38 KEXHP=2
  40 HP=-1.55555E-1*CFM+149.11111
C *** EQUATION GOOD FROM 650 TO 830
     GO TO 600
 100 IF(ANGLE-6.01)105,105,200
 105 IF(CFM-750.)110,110,115
 110 HP=9.30232E-3*CFM+89.02325
     GO TO 600
 115 IF(CFM-900.)120,120,125
 120 HP=-6.0E-2*CFM+141.0
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      GO TO 600
  125 IF(CFM-1065.)130,130,128
  128 KEXHP=6
  130 HP=-1.75757E-1*CFM+245.18181
C *** EQUATION GOOD FROM 900 TO 1065
      GO TO 600
  200 IF(ANGLE-10.01)205,205,300
  205 IF(CFM-850.)210,210,215
  210 HP=2.10526E-2*CFM+122.10526
      GO TO 600
  215 IF(CFM-1050.)220,220,225
  220 HP=-5.0E-2*CFM+182.5
      GO TO 600
  225 IF(CFM-1190.)230,230,235
  230 HP=-1.78571E-1*CFM+317.5
      GO TO 600
  235 IF(CFM-1310.)240,240,238
  238 KEXHP=10
  240 HP=-2.91666E-1*CFM+452.08333
C *** EQUATION GOOD FROM 1190 TO 1310
      GO TO 600
  300 IF(ANGLE-14.01)305,305,400
  305 IF(CFM-1050.)310,310,315
  310 HP=3.63636E-2*CFM+161.81818
      GO TO 600
  315 IF(CFM-1260.)320,320,325
  320 HP=-4.76190E-2*CFM+250.
      GO TO 600
  325 IF(CFM-1580.)330,330,328
  328 KEXHP=14
  330 HP=-1.5625E-1*CFM+386.875
C *** EQUATION GOOD FROM 1260 TO 1580
      GO TO 600
  400 IF(ANGLE-18.01)405,405,500
  405 IF(CFM-1200.)410,410,415
  410 HP=5.42857E-2*CFM+212.85714
      GO TO 600
  415 IF(CFM-1400.)420,420,425
  420 HP=-4.0E-2*CFM+326.
      GO TO 600
  425 IF(CFM-1770.)430,430,428
  428 KEXHP=18
  430 HP=-1.67567E-1*CFM+504.59459
C *** EQUATION GOOD FROM 1400 TO 1770
      GO TO 600
  500 IF(ANGLE-22.01)505,505,600
  505 IF(CFM-1300.)510,510,515
  510 HP=6.0E-2*CFM+270.
      GO TO 600
  515 IF(CFM-1600.)520,520,525
  520 HP=-4.0E-2*CFM+400.
      GO TO 600
  525 IF(CFM-1770.)530,530,528
  528 KEXHP=22
  530 HP=-1.23529E-1*CFM+533.64705
C *** EQUATION GOOD FROM 1600 TO 1770
  600 HP=AMAX1(0.0,HP)
      RETURN
      END


      SUBROUTINE FHPNB11(CFM,HP,ANGLE,NB,KEXHP)
C *** THIS SUBROUTINE CALCULATES FAN TOTAL HORSPOWER -GIVEN THE BLADE
C *** ANGLE AND FLOW-CFM-FOR 11BLADES -12000FPM -127RPM -30FT. FAN
      KEXHP=0
      IF(ANGLE-2.01)5,5,100
    5 IF(CFM-800.)10,10,15
   10 HP=-5.E-2*CFM+100.
      GO TO 600
   15 IF(CFM-955.)20,20,18
   18 KEXHP=2
   20 HP=-1.29032E-1*CFM+163.2258
C *** EQUATION GOOD FROM 800 TO 955
      GO TO 600
  100 IF(ANGLE-6.01)105,105,200
  105 IF(CFM-900.)110,110,115
  110 HP=2.E-2*CFM+92.
      GO TO 600
  115 IF(CFM-1100.)120,120,125
  120 HP=-2.5E-2*CFM+132.5
      GO TO 600
  125 IF(CFM-1280.)130,130,128
  128 KEXHP=6
  130 HP=-1.38888E-1*CFM+257.77777
C *** EQUATION GOOD FROM 1100 TO 1280
      GO TO 600
  200 IF(ANGLE-10.01)205,205,300
  205 IF(CFM-900.)210,210,215
  210 HP=6.66666E-2*CFM+100.
      GO TO 600
  215 IF(CFM-1400.)220,220,225
  220 HP=-4.4E-2*CFM+199.6
      GO TO 600
  225 IF(CFM-1565.)230,230,228
  228 KEXHP=10
  230 HP=-1.69696E-1*CFM+375.57575
C *** EQUATION GOOD FROM 1400 TO 1565
      GO TO 600
  300 IF(ANGLE-14.01)305,305,400
  305 IF(CFM-1100.)310,310,315
  310 HP=6.6E-2*CFM+147.4
      GO TO 600
  315 IF(CFM-1400.)320,320,325
  320 HP=-3.33333E-3*CFM+223.66666
      GO TO 600
  325 IF(CFM-1700.)330,330,335
  330 HP=-6.33333E-2*CFM+307.66666
      GO TO 600
  335 IF(CFM-1870.)340,340,338
  338 KEXHP=14
  340 HP=-1.47058E-1*CFM+450.
C *** EQUATION GOOD FROM 1700 TO 1870
      GO TO 600
  400 IF(ANGLE-18.01)405,405,500
  405 IF(CFM-1200.)410,410,415
  410 HP=9.83333E-2*CFM+185
      GO TO 600
  415 IF(CFM-1500.)420,420,425
  420 HP=5.66666E-2*CFM+235.
      GO TO 600
  425 IF(CFM-1700.)430,430,435
  430 HP=-4.E-2*CFM+380.
      GO TO 600
  435 IF(CFM-1870.)440,440,438
  438 KEXHP=18
  440 HP=-1.E-1*CFM+482.
C *** EQUATION GOOD FROM 1700 TO 1870
      GO TO 600
  500 IF(ANGLE-22.01)505,505,600
  505 IF(CFM-1400.)510,510,515
  510 HP=7.E-2*CFM+268.
      GO TO 600
  515 IF(CFM-1870.)520,520,518
  518 KEXHP=22
  520 HP=2.9787E-2*CFM+324.29787
C *** EQUATION GOOD FROM 1400 TO 1870
  600 HP=AMAX1(0.0,HP)
      RETURN
      END
      SUBROUTINE FHPNB12(CFM,HP,ANGLE,NB,KEXHP)
C *** THIS SUBROUTINE CALCULATES FAN TOTAL HORSPOWER -GIVEN THE BLADE
C *** ANGLE AND FLOW -CFM-FOR 12 BLADES -12000FPM -136RPM -28FT. FAN
      KEXHP=0
      IF(ANGLE-2.01)15,15,100
   15 IF(CFM-700.)20,20,25
   20 HP=-2.5E-2*CFM+77.5
      GO TO 600
   25 IF(CFM-860.)30,30,28
   28 KEXHP=2
   30 HP=-9.375E-2*CFM+125.625
C *** EQUATION GOOD FROM 700 TO 860
      GO TO 600
  100 IF(ANGLE-6.01)105,105,200
  105 IF(CFM-800.)110,110,115
  110 HP=-2.17391E-2*CFM+132.39130
      GO TO 600
  115 IF(CFM-950.)120,120,125
  120 HP=-1.33333E-1*CFM+221.66666
      GO TO 600
  125 IF(CFM-1090.)130,130,128
  128 KEXHP=6
  130 HP=-2.5E-1*CFM+332.5
C *** EQUATION GOOD FROM 950 TO 1090
      GO TO 600
  200 IF(ANGLE-10.01)205,205,300
  205 IF(CFM-900.)210,210,215
  210 HP=-9.375E-3*CFM+173.4375
      GO TO 600
  215 IF(CFM-1050.)220,220,225
  220 HP=-1.E-1*CFM+255.
      GO TO 600
  225 IF(CFM-1200.)230,230,235
  230 HP=-1.8E-1*CFM+339.
      GO TO 600
  235 IF(CFM-1340.)240,240,238
  238 KEXHP=10
  240 HP=-3.07142E-1*CFM+491.57142
C *** EQUATION GOOD FROM 1200 TO 1340
      GO TO 600
  300 IF(ANGLE-14.01)305,305,400
  305 IF(CFM-1000.)310,310,315
  310 HP=3.4E-2*CFM+206.
      GO TO 600
  315 IF(CFM-1200.)320,320,325
  320 HP=-5.E-2*CFM+290.
      GO TO 600
  325 IF(CFM-1300.)330,330,335
  330 HP=-1.1E-1*CFM+362.
      GO TO 600
  335 IF(CFM-1630.)340,340,338
  338 KEXHP=14
  340 HP=-2.0909E-1*CFM+490.81818
C *** EQUATION GOOD FROM 1300 TO 1630
      GO TO 600
  400 IF(ANGLE-18.01)405,405,500
  405 IF(CFM-1000.)410,410,415
  410 HP=4.E-2*CFM+300.
      GO TO 600
  415 IF(CFM-1270.)420,420,425
  420 HP=340.
      GO TO 600
  425 IF(CFM-1400.)430,430,435
  430 HP=-1.E-1*CFM+467.
      GO TO 600
  435 IF(CFM-1550.)440,440,445
  440 HP=-1.93333E-1*CFM+597.66666
      GO TO 600
  445 IF(CFM-1760.)450,450,448
  448 KEXHP=18
  450 HP=-2.66666E-1*CFM+711.33333
C *** EQUATION GOOD FROM 1550 TO 1760
      GO TO 600
  500 IF(ANGLE-22.01)505,505,600
  505 IF(CFM-800.)510,510,515
  510 HP=-1.66666E-2*CFM+398.33333
      GO TO 600
  515 IF(CFM-1100.)520,520,525
  520 HP=8.33333E-2*CFM+318.33333
      GO TO 600
  525 IF(CFM-1460.)530,530,535
  530 HP=410
      GO TO 600
  535 IF(CFM-1770.)540,540,538
  538 KEXHP=22
  540 HP=-1.12903E-1*CFM+574.83870
C *** EQUATION GOOD FROM 1460 TO 1770
  600 HP=AMAX1(0.0,HP)
      RETURN
      END
      SUBROUTINE GEOM1
      DIMENSION XT(3),B2IL(4,4),B2ST(4,4),XNIL(4,4),XNST(4,4),
     1 CROWI(10),CROWS(10)
      COMMON NFO,KGO,KRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QOUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/JUMP/JAKE,TINMX,NOO2I,DTN2I,NOO1I,NFPIN,NOO2O,NOO1O
      COMMON/PIPE/XDIA(20),XLGT(20),NN1,NN2,XTOWR,PLNMH,TTTBH,VX,VN
     1,VAVE
      DATA CROWI/ 0.68,.75,.83,.89,.92,.95,.97,.98,.99,1.0/,
     1     CROWS/ 0.64,.80,.87,.90,.92,.94,.96,.98,.99,1.0/
      DATA XT/1.35,1.75,2.50/,B2ST/.518,.505,.519,.522,.451,.460,.452,
     1 .488,.404,.416,.482,.449,.310,.356,.440,.421/,B2IL/ .348,.275,
     2 .100,.0633,.367,.250,.101,.0678,.418,.299,.229,.198,.290,.357,
     3 .374,.286/, XNST/.556,.554,.556,.562,.568,.562,.568,.568,.572,
     4 .568,.556,.570,.592,.580,.562,.574/,XNIL/.592,.608,.704,.752,
     5 .586,.620,.702,.744,.570,.602,.632,.648,.601,.584,.581,.608/
C
C *** JAKE=1  BUNDLE AND TUBE DESIGN CHANGE
C *** JAKE=2  BUNDLE DESIGN CHANGE ONLY
C *** JAKE=3  NO CHANGE
C
   40 DLTO=DLOV*12.0
      GO TO(45,236,2000),JAKE
   45 CONTINUE
      NP=AMIN1(20.0,ZNTP)+0.01
      NR=AMIN1(20.,ZNTR)+0.01
   50 DTO=1.0
   70 DTT=0.083
   80 DTIM=DTO-2.0*DTT
      DTI=DTIM
      DFR=DTO
C *** FINNED TUBE DIMENSIONS
  110 ZNF=ZNFI
      IF (ZNFI-.0001) 112,112,114
  112 ZNF=10.0
  114 CONTINUE
  116 DFH=0.625
  120 DFT=0.018
  122 DEQ=DFR+ZNF*DFT*DFH*2.0
      DTF=DFR+2.0*DFH
C *** CHECK IF FIN THICK. AND FINS/INCH ARE REASONABLE
      IF (DFT*ZNF-1.0) 140,130,130
  130 ZNFI=0.0
      GO TO 112
  140 RAOR=1.0+2.0*ZNF*DFH*(1.0+(DFH+DFT)/DFR)
  150 AOF=RAOR*PI*DFR/12.0
  160 DFS=1.0/ZNF-DFT
      AR=PI*DFR/12.0*(1.0-ZNF*DFT)
      RARAF=AR/(AOF-AR)
      CFR=DFH/12.0*SQRT(24.0/(TKF*DFT))
      CFR=CFR*(1.0+0.5*DFT/DFH)*(1.0+0.35*ALOG(1.0+2.0*DFH/DFR))
C *** TUBE PITCH, TRANSVERSE AND LATERAL TO FLOW
  224 PL=.5*PT/.5774
      SMAX=15000.
      DHGT=ZNTR*PL+DTO
      DLTS=DHGT*SQRT(2.5*.75*PDI/SMAX)
      DTSMN=.75
      DLTS=AMAX1(DLTS,DTSMN)*2.0
      RPT=PT/DFR
C *** CALC. TUBE RESISTANCE
      RAOI=AOF/(PI*DTIM/12.0)
      RFI=AOF/(2.0*PI*TKF)*ALOG(DFR/DTO)
      RTW=AOF/(2.0*PI*TKT)*ALOG(DTO/DTIM)+RFI
      RFTOT=.0005*RAOI
      RTOT=RFTOT+RTW
C *** FIND TIP-TO-TIP BUNDLE HEIGHT
      TTTBH=(PL*(ZNTR-1.)+DTF)/12.
C *** SET UP SOME BUNDLE COST INFORMATION NEEDED BY ACCOST
      NOO2I=0
      DTN2I=0.
      NOO1I=ZNOZ(1)
      NFPIN=ZNF
      IF((-1)**NTP)710,710,720
  710 NOO1O=0
      NOO2O=ZNOZ(2)
      GO TO 730
  720 NOO1O=ZNOZ(2)
      NOO2O=0
  730 CONTINUE
  234 TLA=ATAN(.5*PT/PL)*57.3
C *** CALC. EFFECTIVE BUNDLE WIDTH. ALLOW 2IN. FOR STRUCT. EACH SIDE.
  236 CONTINUE
  240 Z=ZNTT/ZNTR
      NT1=Z
      IF (ABS(Z-FLOAT(NT1))-0.0001) 244,244,242
  242 NT1=NT1+1
  244 Z=NT1
      DBW=PT*Z
C *** STAGGERED ARRANGEMENT
  250 CLER=DBW-((0.5+FLOAT(NT1-1))* PT+DTF)-.03125
C *** TUBE COUNT EQUATIONS - PER BUNDLE
  308 IF (CLER+.0001) 314,320,320
  314 NT2=NT1-1
      GO TO 326
C *** IN-LINE ARRANGEMENT
  320 NT2=NT1
  326 NTT=0
      DO 350 I=1,NR
      IF ((-1)**I) 330,340,340
  330 NTT=NTT+NT1
      GO TO 350
  340 NTT=NTT+NT2
  350 CONTINUE
  354 NT2=NTT
  356 NTT=ZNTT+0.01
  410 ZTPPA=ZNTT/ZNTP
  436 NTTP=NTT/NTP
      DO 450 I=1,NP
  450 ZTPP(I)=NTTP
  460 NTOV=NTT-NTP*NTTP
  464 IF (NTOV) 500,500,470
  470 DO 480  I=1,NP
      ZTPP(I)=ZTPP(I)+1.0
      NTOV=NTOV-1
      IF (NTOV) 500,500,480
  480 CONTINUE
      GO TO 464
  500 CONTINUE
C *** TUBE SPACER WIDTH ASSUMMED 2 IN.-USED EVERY 6 FT.
  650 DLSP=2*IFIX(DLTO/71.9-1.0)
      DLTE=DLTO-DLSP-DLTS
C *** CALC. APPROAC AREA/BUND. (APPR), PLOT AREA/BAY (APLOT), AND MIN.
C *** CROSSFLOW AREA (AMIN)
      APPR=DLTE*DBW/144.0
      AMIN=APPR*(PT-DEQ)/PT
      RAPMX=AMIN/APPR
C *** SURFACE AREA CALCULATION
      ASBUN=ZNTT*DLTE*AOF/12.0
      ASTOT = ASBUN * ZBUS * ZBUP * ZBYP
C *** CALC. TUBE SIDE CROSSFLOW AREAS
      AX=PI*(DTI/12.0)**2*0.25
      DO 800 I=1,NP
      AXPP(I)=AX*ZTPP(I)
  800 CONTINUE
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      AXAV=AX*ZTPPA
C *** SET UP CONSTANTS FOR AIR SIDE HT AND DP RELATIONS
 1040 IF(JAKE.EQ.2)GO TO 1500
 1072 PLP=PL/COS(TLA*.01745)
      C=1.0
 1080 CFP(1)=6.03/RPT**.8715*RAOR**0.43 *(PT/PLP)**.515 *C
      CFP(2)=-0.245
 1086 DKL=4.0*PT*PL*(1.0-DEQ /PT)/(RAOR*PI*DFR)
 1206 CONTINUE
C *** BRIGGS AND YOUNG GEOMETRY PARAMETERS
 1260 CFH(1)=0.1378*12.0/DFR*(DFS/DFH)**0.296
      CFH(2)=0.718
 1302 CFH(3)=        (1.0-0.3/ZNTR)*1.05
 1500 CONTINUE
      CALL ERORF (KER,KERR,KGO,MM)
 2000 RETURN
      END
```

```
      SUBROUTINE GEOM2(CAPIP)
C *** THIS ROUTINE DESIGNS THE COOLING TOWER PIPING AND CONVERTS ALL
C *** VALVES AND FITTINGS INTO EQUIVALENT LENGTHS.  THE DESIGN FOLLOWS
C *** A LINE FROM A SINGLE PUMP TO THE LAST TOWER BAY AND BACK TO THE
C *** POWER PLANT.  THE LOSSES FROM CONTRACTIONS AND EXPANSIONS IN THE
C *** SUPPLY AND RETURN LINES ARE IGNORED.  THE COOLING TOWERS ARE
C *** ASSUMED TO LAY PERPENDICULAR TO THE PIPING RUNNING TO AND FROM THE
C *** POWER PLANT WITH THE PIPING ENTERING AT THE MIDDLE OF THE COOLING
C *** TOWERS. THE BAYS ARE ARRANGED IN A BACK-TO-BACK SCHEME.
C *** ASSUME ALL PIPES ARE STANDARD WALL AND THAT INLET AND OUTLET
C *** PIPE SIZES ARE THE SAME. BREAK UP SUPPLY AND RETURN LINES
C *** INTO 4 DIFFERENT SIZES.
C ***
C *** THE OUTPUT ARRAYS ARE XDIA AND XLGT, BOTH IN INCHES
C *** THESE ARRAYS ACCOUNT FOR THE FOLLOWING LOSSES:
C ***
C *** 1 = POWER PLANT TO COOLING TOWERS
C *** 2 = COOLING TOWER TO SUPPLY LINE
C *** 3 = TURN INTO SUPPLY LINE AND FIRST LENGTH OF SUPPLY LINE
C *** 4 = SECOND LENGTH OF SUPPLY LINE
C *** 5 = THIRD LENGTH OF SUPPLY LINE
C *** 6 = FOURTH LENGTH OF SUPPLY LINE
C *** 7 = INLET FEEDER LINE LOSS
C *** 8 = TURN INTO INLET HEADER AND HEADER LOSS
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C *** 9 = TURN OUT OF INLET HEADER TO BUNDLE INLET NOZZLE
C *** 10= 0.
C *** 11= TURN FROM BUNDLE OUTLET NOZZLE INTO OUTLET HEADER
C *** 12= LOSS IN OUTLET HEADER AND TURN OUT OF HEADER
C *** 13= OUTLET FEEDER LINE LOSS
C *** 14= FOURTH LENGTH OF RETURN LINE
C *** 15= THIRD LENGTH OF RETURN LINE
C *** 16= SECOND LENGTH OF RETURN LINE
C *** 17= FIRST LENGTH OF RETURN LINE AND TURN OUT OF RETURN LINE
C *** 18= RETURN LINE TO BOUNDARY OF COOLING TOWER
C *** 19= COOLING TOWER TO POWER PLANT
C *** 20= 0.
      COMMON/BCK/XMCST(20),PIPDM(20),XSHOP(20),FIELD(20),EXJOT(20)
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,1MTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,1LA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/PIPE/XDIA(20),XLGT(20),NN1,NN2,XTOWR,PLNMH,TTTBH,VX,VN
     1,VAVE
      COMMON/JAN7/WBMAX,PBPMN,TBPMN,CPEFF,WTEFF,PBPHT,EBPOM,PPOM,CWRTI,
     1SCPMP,CCPMP,FDMAX,MXFBL,SPRNZ,SPRHT,CWTLV,DPPCT,PDMAX,CONCT
      COMMON/CONTL/CSTOR,INML,D(13)
      DIMENSION GPMD(3),PUMPD(3),VALVE(6),DIARR(20),VLARR(20)
C *** ARRAY OF COSTS OF BUTTERFLY VALVES (1976 PRICES)
      DATA VLARR/ 700.00, 1500.0, 3000.0, 4500.0, 6700.0,
     1            8000.0, 10200., 12200., 15800., 19300.,
     2            25800., 27300., 30000., 32800., 38000.,
     3            41500., 47900., 54100., 58000., 85000./
C *** ARRAY OF PIPE SIZES (INCHES)
      DATA DIARR/4.026,8.071,12.09,17.25,23.25,29.25,35.25,42.,48.,54.,
     1            60., 66., 72., 78., 84., 90., 96., 108., 114., 144./
C *** COST OF THE 3 CIRC. PUMPS WITH PUMP DRIVES WITHOUT WATER RECOVERY
C *** TURBINES (1976 PRICES)
      DATA PUMPD/265610.,355220.,520810./
C *** CAPACITIES OF THE 3 CIRCULATING PUMPS USED IN GPM
      DATA GPMD/82700.,110300.,165400./
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C
C *** PIPES BELOW 48 INCH DIAMETER HAVE PROPORTIONATELY MORE MACHINING
C *** AND PIPES ABOVE 48 HAVE THICKER WALLS. AS A RESULT ALL PIPES WORK
C *** OUT TO A COST OF 2. DOLLARS/FOOT/DIAMETER INCH
C *** USE SHOP JOINT COST OF 4 DOLLARS/DIAMETER INCH
C *** USE FIELD JOINT LABOR AS 24 DOLLARS/HOUR
      DATA BIGPI,SMPIP,SJ,FJ/2.,2.,4.,24./
C
      XDIA(10)=0.
      XDIA(20)=0.
C *** CALCULATE THE VARIOUS PIPE SIZES USED IN THE PIPING DESIGN
      D(6)=D(5)/1.414
      D(7)=SQRT(W(1)/ZBYP*2./DEN12(1,1)/VN/19.635)
      D(8)=D(5)*.6124
      D(10)=D(7)/1.414
C *** ASSUME 10000 GPM FILL LINES
      D(11)=SQRT(10000./VX/2.448)
      D(12)=D(5)*.433
      D(13)=D(5)/2.828
      D(1)=D(10)*SQRT(VN/VAVE)
      D(2)=D(1)/1.414
      D(3)=DNZ(1)
      D(4)=DNZ(2)
C *** FIND PIPE SIZES
      DO 100 I=1,13
       IF(I.EQ.3.OR.I.EQ.4)GO TO 100
       CALL NOZID(0.,1.E08,D(I),IDUM,DUM,0)
  100 CONTINUE
C *** SET CODE FOR NECESSARY ARRANGEMENT
C *** FIND STANDARD LENGTH FOR SUPPLY AND RETURN LINES
       STLGT=ZBUP*(DBW+4.)*(ZBYP-4.)/16.
C
C *** FIND LENGTHS AND DIAMETERS TO USE FOR PRESSURE DROP CALCULATIONS
C
       XDIA(1)=D(5)
       XDIA(2)=D(6)
       XLGT(2)=0.
       XLGT(3)=STLGT
       XDIA(4)=D(7)
       XLGT(4)=STLGT
       XDIA(5)=D(8)
       XLGT(5)=STLGT
       XDIA(6)=D(9)
       XLGT(6)=STLGT
       XDIA(7)=D(1)
       XLGT(7)=195.*XDIA(7)+12.*XTOWR
       XDIA(8)=D(2)
       XLGT(8)=90.*XDIA(8)+(DBW+4.)*(ZBUP/2.-.5/ZNOZ(1))
       XDIA(9)=D(3)
       XLGT(9)=135.*XDIA(9)
      XDIA(11)=D(4)
      XLGT(11)=120.*XDIA(11)
      XDIA(12)=D(2)
      XLGT(12)=60.*XDIA(12)+(DBW+4.)*(ZBUP/2.-.5/ZNOZ(2))
      XDIA(13)=D(1)
      XLGT(13)=180.*XDIA(13)+12.*XTOWR
      XLGT(14)=STLGT
      XDIA(14)=D(13)
      XLGT(15)=STLGT
      XDIA(15)=D(12)
      XLGT(16)=STLGT
      XDIA(16)=D(10)
      XLGT(17)=STLGT
      XDIA(17)=D(9)
      XLGT(18)=0.
      XDIA(18)=D(6)
      GO TO (130,140,150,160),INML
  130 XLGT(1)=DLTO+120.*XDIA(1)+12.*DPPCT
      XDIA(3)=XDIA(2)
      XLGT(3)=XLGT(3)+90.*XDIA(3)
      XLGT(17)=XLGT(17)+60.*XDIA(17)
      GO TO 300
  140 XDIA(1)=D(6)
      XLGT(1)=DLTO+120.*XDIA(1)+12.*DPPCT
      XDIA(3)=XDIA(2)
      XLGT(3)=XLGT(3)+20.*XDIA(3)
      XDIA(18)=D(9)
      GO TO 300
  150 XLGT(1)=120.*XDIA(1)+12.*DPPCT
      XDIA(2)=D(9)
      XLGT(2)=170.*XDIA(2)
      XDIA(3)=XDIA(2)
      XDIA(17)=D(6)
      XLGT(18)=140.*XDIA(18)
      GO TO 300
  160 XDIA(1)=D(6)
      XLGT(1)=120.*XDIA(1)+12.*DPPCT
      XDIA(2)=D(9)
      XLGT(2)=80.*XDIA(2)+2.*DLTO
      XDIA(3)=XDIA(2)
      XLGT(3)=XLGT(3)+20.*XDIA(3)
      XDIA(17)=D(6)
      XLGT(17)=XLGT(17)+20.*XDIA(17)
  300 CONTINUE
      XDIA(19)=XDIA(1)
      XLGT(19)=XLGT(1)
      IF(INML.LT.3)GO TO 305
      XDIA(4)=D(10)
      XDIA(5)=D(12)
      XDIA(6)=D(13)
      XLGT(13)=XLGT(13)+20.*XDIA(13)
      XDIA(14)=D(9)
      XDIA(15)=D(8)
      XDIA(16)=D(7)
      XLGT(19)=XLGT(19)+DLTO
      GO TO 306
  305 CONTINUE
      XLGT(7)=XLGT(7)+72.+20.*XDIA(7)
      XLGT(18)=100.*XDIA(18)
  306 CONTINUE
C
C *** FIND MATERIAL COSTS FOR ALL PIPELINES
C *** 1 = INLET FEEDER LINE
C *** 2 = OUTLET FEEDER LINE
C *** 3 = INLET HEADER
C *** 4 = OUTLET HEADER
C *** 5 = SUPPLY LINE NUMBER 1
C *** 6 = SUPPLY LINE NUMBER 2
C *** 7 = SUPPLY LINE NUMBER 3
C *** 8 = SUPPLY LINE NUMBER 4
C *** 9 = SUPPLY LINE NUMBER 5
C *** 10= SUPPLY LINE NUMBER 6
C *** 11= RETURN LINE NUMBER 1
C *** 12= RETURN LINE NUMBER 2
C *** 13= RETURN LINE NUMBER 3
C *** 14= RETURN LINE NUMBER 4
C *** 15= RETURN LINE NUMBER 5
C *** 16= RETURN LINE NUMBER 6
C *** 17= FILL LINES
C *** 18= BYPASS LINES
C
      PIPRA=BIGPI/SMPIP
      XMCST(1)=XTOWR+.4*D(1)
      PIPDM(1)=D(1)
      PIPDM(2)=D(1)
      XMCST(3)=D(2)*SMPIP*(DBW+4.)/12.*(ZBUP-1./ZNOZ(1))
      PIPDM(3)=D(2)
      PIPDM(4)=D(2)
      XMCST(4)=XMCST(3)*(ZBUP-1./ZNOZ(2))/(ZBUP-1./ZNOZ(1))
      XMCST(5)=DPPCT
      PIPDM(5)=XDIA(1)
      STNRD=STLGT*2./12.
      XMCST(6)=STNRD
      PIPDM(6)=XDIA(3)
      XLZ=STNRD
      IF(INML.GT.2)XLZ=2.*STNRD
      DO 600 I=7,9
      XMCST(I)=XDIA(I-3)*XLZ*SMPIP
      PIPDM(I)=XDIA(I-3)
  600 CONTINUE
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      XMCST(10)=0.
      PIPDM(10)=D(6)
      XMCST(11)=DPPCT+DLTO/12.
      PIPDM(11)=XDIA(1)
      XLZ=STNRD
      IF(INML.LT.3)XLZ=2.*STNRD
      XMCST(12)=XLZ
      PIPDM(12)=XDIA(17)
      DO 700 I=13,15
      XMCST(I)=SMPIP*XLZ*XDIA(29-I)
      PIPDM(I)=XDIA(29-I)
  700 CONTINUE
      XMCST(16)=0.
      PIPDM(16)=D(6)
      XMCST(17)=2.*DPPCT*SMPIP*D(11)
      PIPDM(17)=D(11)
      PIPDM(18)=PIPDM(5)
      XMCST(18)=4.*PIPDM(18)/12.*SMPIP*PIPDM(18)
      XMCST(2)=XMCST(1)
      GO TO(550,575,625,650),INML
  550 XMCST(1)=XMCST(1)+6.+.4*D(1)
      XMCST(5)=XMCST(5)+DLTO/12.
      XMCST(12)=XMCST(12)+4.*.4*D(9)
      XMCST(16)=4.*.4*D(6)*SMPIP*D(6)
      GO TO 675
  575 XMCST(1)=XMCST(1)+6.+.4*D(1)
      XMCST(5)=2.*(XMCST(5)+DLTO/12.)+2.*.4*D(6)
      XMCST(11)=2.*XMCST(11)
      XMCST(12)=XMCST(12)+.4*10.*D(9)
      XMCST(17)=2.*XMCST(17)
      XMCST(18)=2.*XMCST(18)
      GO TO 675
  625 XMCST(2)=XMCST(2)+.4*D(1)
      XMCST(6)=2.*XMCST(6)+8.*.4*D(9)
      XMCST(10)=D(6)*SMPIP*(2.*DLTO/12.+.4*D(6))
      XMCST(12)=XMCST(12)+4.*.4*D(6)
      GO TO 675
  650 XMCST(2)=XMCST(2)+.4*D(1)
      XMCST(5)=2.*XMCST(5)
      XMCST(6)=2.*XMCST(6)+10.*.4*D(9)+4.*DLTO/12.
      XMCST(11)=2.*XMCST(11)+2.*.4*D(6)
      XMCST(17)=2.*XMCST(17)
      XMCST(18)=2.*XMCST(18)
  675 CONTINUE
      XMCST(1)=XMCST(1)*D(1)*SMPIP
      XMCST(2)=XMCST(2)*D(1)*SMPIP
      XMCST(5)=XMCST(5)*SMPIP*XDIA(1)
      XMCST(6)=XMCST(6)*SMPIP*XDIA(3)
      XMCST(11)=XMCST(11)*XDIA(1)*SMPIP
      XMCST(12)=XMCST(12)*SMPIP*XDIA(17)
      WPING=0.0
      DO 710 I=1,18
C *** 10 PCT. ADDED TO MATERIAL FOR WELD NECKS,ETC.
      XMCST(I)=1.1*XMCST(I)
      IF(PIPDM(I).GT.48.01)GO TO 708
C *** ASSUME PIPE THICKNESS OF .375 INCHES AND FIND VOLUME OF PIPE METAL
      VPING=XMCST(I)*37.699/PIPDM(I)/SMPIP*(.375**2+.375*PIPDM(I))
      GO TO 709
C *** ASSUME PIPE THICKNESS OF .5 INCH AND FIND VOLUME OF PIPE METAL
  708 VPING=XMCST(I)*37.699/PIPDM(I)/SMPIP*(.5**2+.5*PIPDM(I))
      XMCST(I)=XMCST(I)*PIPRA
  709 IF(I.LE.4)VPING=ZBYP*VPING
      WPING=WPING+VPING
  710 CONTINUE
C *** TO CALCULATE TOTAL PIPING WEIGHT USE .2833 LB/IN3
      WPING=WPING*.2833
C *** FIND PIPING SHIPPING COST BY ASSUMING 5.00 $/CWT
      SHIPCO=WPING*.05
C
C *** FIND SHOP LABOR FOR ALL PIPING
C
      XSHOP(1)=SJ*D(1)
      XSHOP(2)=XSHOP(1)
      TEMY=D(1)+6.*D(2)
      XSHOP(3)=SJ*(TEMY+2.*D(3)*ZNOZ(1)*ZBUP)
      XSHOP(4)=SJ*(TEMY+2.*D(4)*ZNOZ(2)*ZBUP)
      TEMY=ZBYP/2.*D(1)
      XSHOP(5)=D(5)*SJ
      XSHOP(6)=SJ*(TEMY+14.*D(9))
      XSHOP(7)=2.*D(7)
      XSHOP(8)=SJ*TEMY
      XSHOP(9)=XSHOP(8)
      XSHOP(10)=0.
      XSHOP(11)=XSHOP(5)
      XSHOP(13)=4.*D(10)
      XSHOP(14)=XSHOP(8)
      XSHOP(15)=XSHOP(14)
      XSHOP(16)=0.
      XSHOP(17)=0.
      XSHOP(18)=0.
      GO TO(725,750,775,800),INML
  725 XSHOP(1)=2.*XSHOP(1)
      XSHOP(6)=SJ*(TEMY+4.*D(6))
      XSHOP(12)=11.*D(9)
      XSHOP(16)=SJ*9.*D(6)
      GO TO 840
  750 XSHOP(1)=2.*XSHOP(1)
      XSHOP(5)=0.
      XSHOP(6)=SJ*(TEMY+2.*D(6))
      XSHOP(11)=D(6)*SJ*2.
      XSHOP(12)=16.*D(9)
      GO TO 840
  775 XSHOP(2)=2.*XSHOP(2)
      XSHOP(7)=4.*D(10)
      XSHOP(10)=SJ*7.*D(6)
      XSHOP(12)=7.*D(6)
      XSHOP(13)=2.*D(7)
      GO TO 840
  800 XSHOP(2)=2.*XSHOP(2)
      XSHOP(5)=D(6)*SJ
      XSHOP(7)=4.*D(10)
      XSHOP(11)=0.
      XSHOP(12)=2.*D(6)
      XSHOP(13)=2.*D(7)
  840 CONTINUE
      XSHOP(7)=SJ*(XSHOP(7)+TEMY)
      XSHOP(12)=SJ*(XSHOP(12)+TEMY)
      XSHOP(13)=SJ*(XSHOP(13)+TEMY)
C
C *** FIND FIELD LABOR FOR ALL PIPING
C
      FIELD(1)=FJ*(1.4+1.6*D(1))
      FIELD(2)=FIELD(1)
      IF(INML-3)860,870,870
  860 FIELD(1)=2.*FIELD(1)
  870 CONTINUE
      IF(XTOWR-SCPMP)890,890,880
  880 XTRA=AINT(XTOWR/SCPMP-.01)*FJ*(1.4+1.6*D(1))
      FIELD(1)=FIELD(1)+XTRA
      FIELD(2)=FIELD(2)+XTRA
  890 FIELD(3)=ZBUP*ZNOZ(1)*FJ*(1.4+1.6*D(3))
      FIELD(4)=ZBUP*ZNOZ(2)*FJ*(1.4+1.6*D(4))
      DO 900 I=5,18
      EXJOT(I)=0.
      FIELD(I)=0.
  900 CONTINUE
      FIELD(18)=FJ*4.*(1.4+1.6*PIPDM(18))
      GO TO(910,920,930,940),INML
  910 FIELD(6)=2.*FJ*(1.4+1.6*D(6))
      FIELD(11)=FJ*(1.4+1.6*D(5))
      FIELD(12)=FJ*(1.4+1.6*D(9))*5.
      FIELD(16)=FIELD(6)
      GO TO 950
  920 FIELD(5)=FJ*(1.4+1.6*D(6))*2.
      FIELD(11)=FIELD(5)
      FIELD(12)=FJ*(1.4+1.6*D(9))*6.
      FIELD(18)=2.*FIELD(18)
      GO TO 950
  930 FIELD(6)=FJ*(1.4+1.6*D(9))*6.
      FIELD(10)=FJ*(1.4+1.6*D(6))
      FIELD(12)=3.*FIELD(10)
      GO TO 950
  940 FIELD(6)=FJ*(1.4+1.6*D(9))*6.
      FIELD(11)=FJ*(1.4+1.6*D(6))*2.
      FIELD(18)=2.*FIELD(18)
  950 CONTINUE
C
C *** ALL LONG PIPES MUST HAVE ADDITIONAL FIELD JOINTS, SHOP JOINTS,
C *** AND EXPANSION JOINTS DUE TO THEIR LENGTH
C
      DO 1000 I=5,15
      IF(I-5)960,960,970
  960 LENG=DPPCT
      IF(INML.LT.3)LENG=LENG+DLTO/12.
      PIECE=1.
      IF((-1)**INML.GT.0)PIECE=2.
      GO TO 990
  970 IF(I-11)975,980,985
  975 IF(I.NE.10)GO TO 976
      IF(INML.NE.3)GO TO 1000
      LENG=2.*DLTO/12.
      PIECE=1.
      GO TO 990
  976 IF(I.NE.6)GO TO 978
      IF(INML.NE.4)GO TO 978
      LENG=DLTO/12.
      PIECE=4.
      CALL PIPDIV(PIPDM(I),LENG,PIECE,SCPMP,FJ,SJ,I)
  978 LENG=STLGT/12.
      PIECE=2.
      IF(INML.GT.2)PIECE=4.
      GO TO 990
  980 LENG=DPPCT+DLTO/12.
      PIECE=1.
      IF((-1)**INML.GT.0)PIECE=2.
      GO TO 990
  985 LENG=STLGT/12.
      PIECE=2.
      IF(INML.LT.3)PIECE=4.
  990 CALL PIPDIV(PIPDM(I),LENG,PIECE,SCPMP,FJ,SJ,I)
 1000 CONTINUE
      LENG=DPPCT
      PIECE=2.
      IF((-1)**INML.GT.0)PIECE=4.
      CALL PIPDIV(PIPDM(17),LENG,PIECE,SCPMP,FJ,SJ,17)
      XNL=PIECE/2.
C *** ASSUME 1 FILL PUMP PER LINE AT 20000 DOLLARS FOR PUMP AND DRIVE
      PUMPF=20000.*XNL
C
C *** CALCULATE COST OF CONDENSATE PUMPS
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C
      GPMSL=W(1)/XNL/DEN12(1,1)/8.021
      PUMPC=1.E11
      DO 1500 I=1,3
      IPUMP=IFIX(GPMSL/GPMD(I))+1
      PUMPI=FLOAT(IPUMP)*PUMPD(I)
      IF(PUMPI-PUMPC)1300,1500,1500
 1300 PUMPC=PUMPI
      NPUMP=IPUMP
      PPGPM=GPMD(I)
 1500 CONTINUE
      PUMPC=PUMPC*XNL
      IXNL=XNL
      NPUMP=NPUMP*IXNL
C *** FIND COST OF BUTTERFLY VALVES
C *** VALVE(01) = EACH BAY HAS 2 CONTROL VALVES
C *** VALVE(02) = EACH SUPPLY LINE HAS 2 CONDENSATE PUMP ISOLATION VALVE
C *** VALVE(03) = EACH RETURN LINE HAS 2 RECOVERY TURB. ISOLATION VALVES
C *** VALVE(04) = EACH PAIR OF LINES HAS 3 BYPASS VALVES
C *** VALVE(05) = EACH SUPPLY FILL LINE HAS 2 FILL PUMP ISOLATION VALVES
C *** VALVE(06) = EACH RETURN FILL LINE HAS 2 FILL DRAIN VALVES
      VALVE(1)=2.*ZBYP*GRS(DIARR,1,VLARR,1,D(1),20,JDUM)
      VLVCT=GRS(DIARR,1,VLARR,1,PIPDM(5),20,JDUM)*XNL
      VALVE(2)=2.*VLVCT
      VALVE(3)=0.
      IF(CWRTI.LE..05)GO TO 1600
      VALVE(3)=VALVE(2)
 1600 VALVE(4)=3.*VLVCT
      VLVCT=GRS(DIARR,1,VLARR,1,PIPDM(17),20,JDUM)*XNL
      VALVE(5)=2.*VLVCT
      VALVE(6)=VALVE(5)
C *** CALCULATE STORAGE TANK VOLUME BASED ON 1.5 CAPACITY FACTOR
C *** TANKS MUST HOLD THE TUBE AND FEEDER LINE VOLUME PLUS EXTRA 1.5 TO
C *** ACCOUNT FOR HEADERS AND OTHER ABOVE GROUND PIPING. ASSUME
C *** RETURN AND SUPPLY LINES NEED NOT BE COMPLETELY DRAINED.
      VFILL=DLTO*ZBYP*ZBUP*FLOAT(NTT)*.7854*DTIM**2
      VFILL=VFILL+.7854*D(1)**2*XTOWR*ZBYP*12.*2.
      VFILL=1.5*VFILL/231.
C *** ASSUME TANKS ARE 40 FEET LONG AND 3/8 INCHES THICK. COST IS
C *** 1.10 $/LB INSTALLED WITH AN EXTRA 2.25 $/GAL FOR THE PIT.
C *** ASSUME MAXIMUM TANK SIZE OF 150000 GALLONS.
      NTANK=VFILL/150000.+1
      XTANK=NTANK
      VFILL=VFILL/XTANK
C *** SEE NOTEBOOK FOR DERIVATION OF FORMULAS
      DTANKA=ACOS(1.-VFILL/250673.96)
      DTANK=80.*COS(DTANKA/3.+4.18879)+40.
      WTANK=16.02*(240.2*DTANK+7.4-DTANK**2)
      TANKC=XTANK*(1.1*WTANK+2.25*VFILL)
C *** ADD IN SHIPMENT COST OF TANKS AT 5.00 $/CWT
```

```
      SHIPCO=SHIPCO+.05*WTANK*XTANK
C *** ASSUME CONTROLS ARE 9 PCT. OF BUNDLE COST
      CONTR=.09*CSTOR
C *** ASSUME 13350 DOLLARS FOR NITROGEN BLANKETING
      BLANN=13350.
C *** FIND TOTAL COST OF PIPING SYSTEM
      CAPIP=PUMPF+PUMPC+TANKC+CONTR+BLANN
      DO 1800 I=1,4
      CAPIP=CAPIP+ZBYP*(XMCST(I)+XSHOP(I)+FIELD(I))+VALVE(I)
 1800 CONTINUE
      CAPIP=CAPIP+VALVE(5)+VALVE(6)
      DO 1900 I=5,18
      CAPIP=CAPIP+XMCST(I)+XSHOP(I)+FIELD(I)+EXJOT(I)
 1900 CONTINUE
      CAPIP=CAPIP+SHIPCO
      NN1=IXNL
      NN2=NN1
      IF(KNTR1.EQ.0)GO TO 5000
      CALL CHANL(NFO,ZBYP,VALVE,NPUMP,PPGPM,PUMPC,IXNL, PUMPF,VFILL,
     1TANKC,CONTR,BLANN,SHIPCO,CAPIP,NTANK,INML)
 5000 CONTINUE
      RETURN
      END
```

```
      FUNCTION GRS (X,NDX,Y,NDY,XV,N,NRANGE)
C
C     THIS FUNCTION INTERPOLATES BETWEEN THE POINTS OF AN ARRAY
C
C     X      - ARRAY OF POINTS ON ABSCISSA
C     Y      - ARRAY OF POINTS ON ORDINATE
C     NDX    - INCREMENT BETWEEN POINTS IN THE X ARRAY
C     NDY    - INCREMENT BETWEEN POINTS IN THE Y ARRAY
C     XV     - VALUE OF X TO FIND FUNCTION FOR
C     N      - NUMBER OF POINTS IN ARRAYS
C     NRANGE - INDICATES EXTRAPOLATION
C
      DIMENSION X(1),Y(1),DX(3),DY(3),YP(2)
      NRANGE=0
C *** CHECK IF XV LIES OUTSIDE RANGE
      IF((XV+.001).LT.X(1).AND.(XV+.001).LT.X(1+NDX*(N-1)))NRANGE=-1
      IF(XV.GT.(X(1+NDX*(N-1))+.001).AND.XV.GT.(X(1)+.001))NRANGE=1
C *** IF X IS DECREASING CHANGE SIGN OF NRANGE
```

```
      IF(X(1).GT.X(1+NDX*(N-1)))NRANGE=(-1)*NRANGE
      IF(NRANGE.NE.0)GO TO 11
      DO 10 I=2,N
      II=I
C *** FIND XV BETWEEN I AND I-1 POINTS
      IF(ABS(XV-X(1+NDX*(I-2))).LT..001)GO TO 4
      IF(XV-X(1+NDX*(I-2)))1,4,2
    1 IF(XV-X(1+NDX*(I-1)))10,70,20
    2 IF(XV-X(1+NDX*(I-1)))20,70,10
    4 II=I-1
      GO TO 70
   10 CONTINUE
C *** IF XV IS OUTSIDE RANGE USE LAST 3 OR FIRST 3 POINTS DEPENDING
C *** ON WHETHER OR NOT X IS DECREASING OR INCREASING
   11 I=N
      IF(NRANGE.EQ.(-1))I=1
   20 IF(I.GT.2)GO TO 30
C *** IF XV IS ON LOW END USE FIRST 3 POINTS
      N1=3
      N2=2
      N3=1
      NP=3
      GO TO 55
   30 IF(I.LT.N)GO TO 40
C *** IF XV IS ON HIGH END USE LAST 3 POINTS
      NP=3
      GO TO 50
C *** USE 4 POINTS - 2 ON EITHER SIDE OF XV
   40 NP=4
      N4=I+1
   50 N1=I-2
      N2=I-1
      N3=I
C
C *** THE FOLLOWING FORMULAS WERE EXTRACTED FROM PAGE 75 OF *CALCULATION
C *** OF PROPERTIES OF STEAM* BY MCCLINTOCK AND SILVESTRI
C
   55 DX(1)=X(1+NDX*(N2-1))-X(1+NDX*(N1-1))
      DY(1)=Y(1+NDY*(N2-1))-Y(1+NDY*(N1-1))
      DX(2)=X(1+NDX*(N3-1))-X(1+NDX*(N2-1))
      DY(2)=Y(1+NDY*(N3-1))-Y(1+NDY*(N2-1))
      R=(XV-X(1+NDX*(N2-1)))/DX(2)
      YP(1)=(DY(1)*DX(2)**2+DY(2)*DX(1)**2)/(DX(1)*(DX(1)+DX(2)))
      IF(NP.EQ.4)GO TO 60
      GRS=Y(1+NDY*(N2-1))+R*(YP(1)+R*(DY(2)-YP(1)))
      GO TO 100
   60 DX(3)=X(1+NDX*(N4-1))-X(1+NDX*(N3-1))
      DY(3)=Y(1+NDY*(N4-1))-Y(1+NDY*(N3-1))
      YP(2)=(DY(2)*DX(3)**2+DY(3)*DX(2)**2)/(DX(3)*(DX(2)+DX(3)))
      GRS=Y(1+NDY*(N2-1))+R*(YP(1)+R*(3.*DY(2)-2.*YP(1)-YP(2)+R*(YP(1)+
     1YP(2)-2.*DY(2))))
      GO TO 100
   70 GRS=Y(1+NDY*(II-1))
  100 RETURN
      END
```

```
      SUBROUTINE HEAD(NTT,NTR,NTP,DSL,DST,DHEDW,DTI,DTO,TSTS,TSTOP,TSBOT
     1,TSIDE,TBACK,TSPP,DEN,CTM,CUTT,CUTL,WLDT,WLDL,CHOLE,DTNZI,DTNZO,CT
     2PG1,ASPG1,KTYPE,CTH,CTCUT,CTWLD,CTTPG,CTOTH,SLAB,SMAT,DHEDD,DHEDH,
     3DWO,DHO,DDO,NPPF,NPPB)
C
C *** INPUT VARIABLES ***
C
C     NTT   = TOTAL NUMBER OF TUBES
C     NTR   = NUMBER OF TUBE ROWS
C     NTP   = NUMBER OF TUBE PASSES
C     DSL   = LONGITUDINAL PITCH (INCH)
C     DST   = TRANSVERSE PITCH (INCH)
C     DHEDW = BUNDLE WIDTH (INCH)
C     DTI   = TUBE INSIDE DIAMETER (INCH)
C     DTO   = TUBE OUTSIDE DIAMETER (INCH)
C     TSTS  = THICKNESS OF TUBE SHEET (INCH)
C     TSTOP = THICKNESS OF TOP PLATE (INCH)
C     TSBOT = THICKNESS OF BOTTOM PLATE (INCH)
C     TSIDE = THICKNESS OF SIDE PLATE (INCH)
C     TBACK = THICKNESS OF BACK PLATE (INCH)
C     TSPP  = THICKNESS OF PASS PARTITION (INCH)
C     DEN   = METAL DENSITY (LB/IN3)
C     CTM   = COST OF METAL SHEET ($/LB)
C     CUTT  = CUTTING SPEED (MIN/INCH)
C     CUTL  = CUTTING LABOR COST ($/HR)
C     WLDT  = WELDING SPEED (MIN/INCH)
C     WLDL  = WELDING LABOR COST ($/HR)
C     CHOLE = HOLE CUTTING COST ($/4INCH THICKNESS)
C     DTNZI = INLET NOZZLE DIAMETER (INCH)
C     DTNZO = OUTLET NOZZLE DIAMETER (INCH)
C     NNZI  = NUMBER OF INLET NOZZLES
C     NNZO  = NUMBER OF OUTLET NOZZLES
C     KTYPE = 1 FOR FRONT HEADER.  2 FOR BACK HEADER
C     CTPG1 = PLUG COST ($/PLUG)
C     ASPG1 = PLUG ASSEMBLING COST ($/PLUG)
C
```

```
C *** OUTPUT VARIABLES ***
C
C      CTOTH = TOTAL COST FOR THE HEADER ($)
C      SLAB  = TOTAL LABOR COST FOR THE HEADER ($)
C      SMAT  = TOTAL MATERIAL COST FOR THE HEADER ($)
C      DHEDD = INSIDE LENGTH OF HEADER (INCH)
C      DHEDH = INSIDE HEIGHT OF HEADER (INCH)
C      DWO    = OUTSIDE WIDTH OF THE HEADER (INCH)
C      DHO    = OUTSIDE HEIGHT OF THE HEADER (INCH)
C      DDO    = OUTSIDE DEPTH OF THE HEADER (INCH)
C      NPPF = NUMBER OF PASS PARTITIONS IN FRONT HEADER
C      NPPB = NUMBER OF PASS PARTITIONS IN BACK  HEADER
C
C
       ZTT=NTT
       ZTR=NTR
       ZTP=NTP
C
C
C *    BUNDLE HEIGHT = NUMBER OF ROWS * LONGITUDINAL PITCH
       DHEDH=ZTR*DSL
C
C      CALCULATE THE CROSSFLOW AREA OF TUBES IN A PASS
       APASS=3.1416/4.0*ZTT/ZTP*DTI**2
C
C      SET THE AREA OF THE HEADER  DHEDW*DHEDD=APASS/2.0 , THEREFORE
       DHED1=APASS/2.0/DHEDW
C
C
       IF(DTNZI-DTNZO) 1,1,2
     1 DTNOZ=DTNZO
       GO TO 3
     2 DTNOZ=DTNZI
     3 CONTINUE
C
       DHED2=DTNOZ*1.2
C
       IF (DHED1-DHED2) 4,4,6
     4 DHEDD=DHED2
       GO TO 8
     6 DHEDD=DHED1
     8 CONTINUE
C
       DWO=DHEDW+2.0*TSIDE
       DHO=DHEDH+TSTOP+TSBOT
       DDO=DHEDD+TSTS+TBACK
C
C *    FROM THE NUMBER OF TUBE PASSES NTP, FIGURE OUT THE NUMBER OF
C      PASS PARTITIONS IN FRONT HEADER AND BACK HEADER
C
```

```
C     NPPF  = NUMBER OF PASS PARTITIONS IN FRONT HEADER
C     NPPB  = NUMBER OF PASS PARTITIONS IN BACK  HEADER
      NPPF=NTP/2
      ZPPF=NPPF
      IF (ZTP/2.0-ZPPF) 10,10,20
   10 CONTINUE
      NPPB=NPPF-1
      GO TO 30
C
   20 CONTINUE
      NPPB=NPPF
C
   30 CONTINUE
      IF (KTYPE-1) 50,50,40
   40 CONTINUE
      NPP=NPPB
      GO TO 60
C
   50 CONTINUE
      NPP=NPPF
C
   60 CONTINUE
      ZPP=NPP
C
C
C --- WEIGHT CALCULATIONS ---
C
C     TUBE SHEET (LB)
      WTTS=DHEDW*DHEDH*TSTS*DEN
C
C     TOP PLATE (LB)
      WTOP=(DHEDW+2.0*TSIDE)*(DHEDD+TSTS+TBACK)*TSTOP*DEN
C
C     BOTTOM PLATE (LB)
      WTBOT=(DHEDW+2.0*TSIDE)*(DHEDD+TSTS+TBACK)*TSBOT*DEN
C
C     TWO SIDE PLATES (LB)
      WSIDE=2.0*DHEDH*(DHEDD+TSTS+TBACK)*TSIDE*DEN
C
C     BACK PLATE
      WBACK=DHEDW*DHEDH*TBACK*DEN
C
C     PASS PARTITION (LB) -- HORIZONTAL
      WTPP=DHEDW*DHEDD*TSPP*DEN*ZPP
C
C     TOTAL WEIGHT OF THE HEADER (LB)
      WTOT=WTTS+WTOP+WTBOT+WSIDE+WBACK+WTPP
C
C     ADD 5( TO TOTAL WEIGHT
      WTOT=WTOT*1.05
```

```
C
C **  COST OF THE HEADER PLATES ($)
     CTH=CTM*WTOT
C
C
C --- LABOR COST ---
C
C    (((CUTTING)))
C    EACH PLATE HAS FOUR SIDES -- CUTTING + FINISHING
C
     PLTS=2.0*(DHEDW+DHEDH)
     PLTOP=2.0*(DHEDW+2.0*TSIDE+DHEDD+TSTS+TBACK)
     PLBOT=PLTOP
     PSIDE=2.0*2.0*(DHEDH+DHEDD+TSTS+TBACK)
     PBACK=PLTS
     PLPP=2.0*ZPP*(DHEDW+DHEDD)
     PLTOT=PLTS+PLTOP+PLBOT+PSIDE+PBACK+PLPP
C
C    SIDE CUTTING COST ($)
     CTSD=PLTOT*CUTT/60.0*CUTL
C
C    HOLE CUTTING COST ($)
C    FOR BUNDLE TUBES + REMOVABLE PLUGS
     CTHL=ZTT*CHOLE
C
C  * CHECK IF THERE IS ANY ADDITIONAL COST FOR CUTTING HOLES ON THE
C  * BACK HEADER
C
     IF (KTYPE-1) 80,80,70
  70 CONTINUE
C    PLUGS ON BOTH THE FRONT AND BACK HEADER
     IF (2.0*TSTS+2.0*TBACK-4.0) 72,72,80
  72 CONTINUE
     CTHL=0.0
C
  80 CONTINUE
C
C ** TOTAL CUTTING COST ($)
     CTCUT=CTSD+CTHL
C
C
C    (((WELDING)))
C    EACH PASS PARTITION HAS EIGHT WELDS (4 LONG,4 SHORT)
C
     PLWLD=8.0*DHEDH+2.0*2.0*((DHEDD+DHEDW)*2.0+TSTS+TBACK+2.0*TSIDE)+Z
    1PP*2.0*2.0*(DHEDW+DHEDD)
C
C ** TOTAL WELDING COST
     CTWLD=PLWLD*WLDT*WLDL/60.0
C
```

```
C
C --- PLUGS COST ---
C
C     PLUG MATERIAL COST
      CMTPG=ZTT*CTPG1
C
C     PLUG ASSEMBLING COST
      CASPG=ZTT*ASPG1
C
C     TOTAL COST FOR PLUGS
      CTTPG=CASPG+CMTPG
C
C
C     TOTAL LABOR COST FOR THE HEADER
      SLAB=CTCUT+CTWLD+CASPG
C
C     TOTAL MATERIAL COST FOR THE HEADER
      SMAT=CTH+CMTPG
C
C
C *** TOTAL BASE COST FOR THE HEADER ***
      CTOTH=CTH+CTCUT+CTWLD+CTTPG
C
      RETURN
      END




      SUBROUTINE HTAIR(GAMAX,DFR,VISAV,REAV,CONAV,PRAV,HAIR,CFH,CFR,
     1RARAF,FINEF,RFIN)
      DIMENSION CFH(3)
C *** INDUCED DRAFT,SMOOTH FIN CORRELATION
      REAV=GAMAX*DFR/(29.0*VISAV)
C *** BRIGGS AND YOUNG CORRATION, HIGH FIN TUBES
   80 HAIR=CFH(1)*CONAV*REAV**CFH(2) *PRAV**.333
  155 CH=CFH(3)
  190 HAIR=CH*HAIR
      HA1=HAIR
      FINEF=CFR*SQRT(HA1)
      FINEF=TANH(FINEF)/FINEF
      RFIN=1.0/HA1*(1.0-FINEF)/(RARAF+FINEF)
  300 RETURN
      END
      SUBROUTINE HTURB(T,H,XLOAD,HTRT,BBP)
C *** GIVEN T IN DEGREES RANKINE THIS SUBROUTINE CALCULATES A HEAT RATE
C *** RATIO,H.  THE BASE HEAT RATE,HTRT,IS THE HEAT RATE WHEN THE
C *** TURBINE IS AT A NOMINAL LOAD OF XLOAD WITH A BACK PRESSURE
C *** OF BBP INCHES OF MERCURY
C
      COMMON ID1,KGO,ID5(4),D1(3),ID2,KER,KERR(20),ID3(4),MM,ID4(7),
     1D2(1218)
      COMMON/STIN/XLDFT(6),BP(28),HTRTD(28,6),HTRJD(28,6),NLODS,NBKPR
     1,PLOAD,BPMNM(6),TPMNM(6)
      COMMON/BCKPR/BCKMN,BCKMX
      COMMON/FAST/STOW(3)
      DIMENSION X(4),N(7),Y(4)
      N1=0
C.
C *** CHANGE T TO DEGREES F
      TT=TCONV(T,1,2)
C *** FROM T FIND EXHAUST PRESSURE IN INCHES-HG ABS.
      BBPP=PSL(TT)
C *** MAKE SURE BBPP IS WITHIN BACK PRESSURE RANGE
      IF(BBPP.LT.BCKMN)BBPP=BCKMN+.00001
      IF(BBPP.GT.BCKMX)BBPP=BCKMX-.00001
      LOOP=1
C *** SET ALL EXTRAPOLATION INDICATORS TO ZERO
    3 DO 5 I=1,7
    5 N(I)=0
      NP=3
C *** SEE IF XLOAD LIES WITHIN THE RANGE OF XLDFT
      IF((XLOAD+.001) .LT.XLDFT(NLODS).AND.(XLOAD+.001) .LT.XLDFT(1))
     1N(1)=-1
      IF(XLOAD.GT.(XLDFT(1)+.001) .AND.XLOAD.GT.(XLDFT(NLODS)+.001) )
     1N(1)=1
      IF(XLDFT(1).GT.XLDFT(NLODS))N(1)=(-1)*N(1)
      IF(N(1).NE.0)GO TO 11
C *** FIND XLOAD BETWEEN I AND I-1 POINTS
      DO 10 I=2,NLODS
      IZ=I
      IF(ABS(XLOAD-XLDFT(I-1)).LT..002)GO TO 4
      IF(XLOAD-XLDFT(I-1))1,4,2
    1 IF(XLOAD-XLDFT(I))10,70,20
    2 IF(XLOAD-XLDFT(I))20,70,10
    4 IZ=I-1
      GO TO 70
   10 CONTINUE
C *** IF XLOAD IS OUTSIDE RANGE OF XLDFT USE LAST 3 OR FIRST 3 POINTS
C *** DEPENDING ON WHETHER OR NOT XLDFT IS DECREASING OR INCREASING
   11 I=NLODS
      IF(N(1).EQ.(-1))I=1
   20 IF(I.GT.2)GO TO 30
C *** IF XLOAD IS  ON LOW END USE FIRST 3 POINTS.  IF IT IS ON HIGH END
```

```
C *** USE LAST 3 POINTS.  OTHERWISE USE 4 POINTS - 2 ON EITHER SIDE
C *** OF XLOAD
      N1=3
      N2=2
      N3=1
      GO TO 50
   30 IF(I.EQ.NLODS)GO TO 40
      NP=4
      N4=I+1
   40 N1=I-2
      N2=I-1
      N3=I
      GO TO 50
   45 IF(N1.EQ.0)GO TO 70
C *** FIND THE HEAT RATES(CORRESPONDING TO THE BACK PRESSURE) OF THE
C *** 3 OR 4 LOADS THAT ARE NEAR XLOAD
   50 X(1)=GRS(BP,1,HTRTD(1,N1),1,BBPP,NBKPR,N(2))
      X(2)=GRS(BP,1,HTRTD(1,N2),1,BBPP,NBKPR,N(3))
      X(3)=GRS(BP,1,HTRTD(1,N3),1,BBPP,NBKPR,N(4))
      Y(1)=XLDFT(N1)
      Y(2)=XLDFT(N2)
      Y(3)=XLDFT(N3)
      IF(NP.EQ.3)GO TO 55
      Y(4)=XLDFT(N4)
      X(4)=GRS(BP,1,HTRTD(1,N4),1,BBPP,NBKPR,N(7))
   55 CONTINUE
C *** FIND THE HEAT RATE FOR XLOAD
      HTRT=GRS(Y,1,X,1,XLOAD,NP,N(5))
      GO TO 100
   70 HTRT=GRS(BP,1,HTRTD(1,IZ),1,BBPP,NBKPR,N(6))
C *** SET MINOR ERROR IF EXTRAPOLATION OCCURRED
  100 DO 200 II=1,7
      IF(N(II))250,200,250
  200 CONTINUE
      GO TO 300
  250 KER=22
      CALL ERORF(KER,KERR,KGO,MM)
C *** SEE IF BOTH HEAT RATES HAVE BEEN CALCULATED
  300 IF(LOOP.EQ.2) GO TO 400
C *** FIND BASE HEAT RATE
      H=HTRT
      LOOP=2
      BBPP=BBP
C *** NO NEED TO RECALCULATE HTRT IF BASE CONDITIONS HAVE NOT CHANGED
      IF(ABS(XLOAD-STOW(1))-.002)320,320,350
  320 IF(ABS(BBP-STOW(2))-.01)340,340,350
  340 HTRT=STOW(3)
      GO TO 400
  350 STOW(1)=XLOAD
      STOW(2)=BBP
      GO TO 45
  400 H=H/HTRT
      STOW(3)=HTRT
      RETURN
      END
```

```
      SUBROUTINE ICHEK
C *** CHECKS INPUT DATA FOR CONSISTENCY
C *** LIMITATION OF INPUT DATA
      DIMENSION KERRO(20)
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
 9010 FORMAT (1H1)
 9020 FORMAT(47H0 MINOR ERRORS FOUND IN INPUT DATA (CALCULATION,
     1 13H CONTINUES)--/7X,10(I4,1H,)/7X,10(I4,1H,))
 9030 FORMAT(48H0  MAJOR ERRORS FOUND IN INPUT DATA (CALCULATION,
     1 9H STOPS)--/7X,10(I4,1H,)/7X,10(I4,1H,))
      NERC=0
      MM=0
      CALL CFIXM(ZTRD , 0.001 ,99.0   ,4.0           ,104,KERRO,NERC)
      CALL CFIXM(ANGI ,-0.001 ,90.01  ,0.0           ,107,KERRO,NERC)
      CALL CFIXM(ZBYP ,.001,1000.,1.0,110,KERRO,NERC)
      CALL CFIXM(ZBUP , 0.001 ,10.01  ,1.0           ,111,KERRO,NERC)
      CALL CFIXM(ZBUS , 0.001 ,4.01   ,1.0           ,112,KERRO,NERC)
      ZTPMX=IFIX(DLOV/19.99)+1
      CALL CFIXM(ZFAN , 0.001 ,10.1   ,ZTPMX         ,113,KERRO,NERC)
      CALL CFIXM(PTI  ,-0.001 ,20.0   ,0.0            ,212,KERRO,NERC)
      CALL CFIXM (TKT   , 0.001  ,500.0  ,26.0       ,215,KERRO,NERC)
      CALL CFIXM (TKF   , 0.001  ,500.0  ,110.0      ,216,KERRO,NERC)
      CALL CFIXM(COST(2),.001 ,1.E5   ,100.0          ,915,KERRO,NERC)
      DO 10 I=1,2
      CALL CFIXM(ZNOZ(I), 0.01,10.0   ,1.0            ,I+816,KERRO,NERC)
   10 CONTINUE
      KCI=2
  356 NTP=ZTPD+0.01
  740 IF (ZNTD*ZNTR-0.01) 746,746,742
  742 IF (ZNTD-ZNTR) 743,746,746
  743 ZNTD=ZNTR
      CALL ERORG(NERC,KERRO,902)
  746 CONTINUE
  748 IF (ZNTD-0.01) 750,750,760
  750 CALL ERORF (105,KERR,KGO,MM)
  760 IF (DLOV-0.01) 770,770,780
  770 CALL ERORF (201,KERR,KGO,MM)
  780 CONTINUE
 1006 GO TO 1080
 1020 CALL ERORF(102,KERR,KGO,MM)
      GO TO 1100
 1080 IF (TIND(1)*TOUTD(1)*WD(1)       *TIND(2)-0.1)
     1 1020,1020,1100
 1100 CONTINUE
      IF (NERC+MM)    9000,9000,8000
 8000 CONTINUE
 8400 IF (NERC)       8600,8600,8500
 8500 WRITE(NFO,9020) (KERRO(I),I=1,NERC)
 8600 IF (MM)         9000,9000,8800
 8800 WRITE(NFO,9030) (KERR(I),I=1,MM)
 9000 RETURN
      END
```

```
      SUBROUTINE ICONV
C *** INPUT UNIT CONVERSION
      DIMENSION IFN(6)
      COMMON IDUM(6),RDUM(3),IDUMW(34),DUMW(246),DUMYD(60),DUM1(912)
      DATA IFN/16,19,20,21,22,25/
      KIN=1
C *** CONVERSION OF TEMPERATURES TO ABSOLUTE
      DO 10 I=1,6
      II=IFN(I)
   10 DUMYD(II)=TCONV(DUMYD(II),KIN,1)
C *** CONVERSION OF U.S. UNITS TO INTERNAL COMPATIBLE
      DUMYD(13)=DUMYD(13)*1.0E3
      DUMYD(14)=DUMYD(14)*4.5E3
      DO 220 I=1,7
  220 DUMYD(I+25)=DUMYD(I+25)*1.0E6
  900 RETURN
      END
```

```
      SUBROUTINE INPUT
C *** S/R INITA CONTROLS DATA HANDLING
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMONPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
   10 CALL IREAD
  200 CONTINUE
      CALL ICONV
      CALL ICHEK
      IF (KGO-1) 300,300,10
  300 CALL PPCON
 1000 RETURN
      END
      SUBROUTINE IREAD                                                  44020
      COMMON IDUM1,KGO,IDUM2(4),DUM(3),IDUM4(34),DUM1(246),RON2(60),    44030
     1DUM3(912)                                                         44040
   20 KGO=1                                                             44050
      RON2(25)=32.                                                      44060
      RON2(41)=50.                                                      44070
      RON2(8)=60.                                                       44080
      RON2(20)=93.                                                      44090
      RON2(19)=156.                                                     44100
      RON2(21)=131.                                                     44110
      RON2(13)=179130.                                                  44120
      RON2(53)=270.                                                     44130
  900 RETURN                                                            44140
      END                                                               44150
```

```
      SUBROUTINE MJBOX(TOL,ALF,DELT,ITRMX,NITR,N)                       44160
C     QMIN=   MINIMUM HEAT REJECT ALLOWED                               44170
C     QMAX=   MAXIMUM HEAT REJECT ALLOWED                               44180
C     TLMAX=  MAXIMUM TUBE LENGTH ALLOWED                               44190
C     TLMIN=  MINIMUM TUBE LENGTH ALLOWED                               44200
C     TITDN=  MINIMUM ITD ALLOWED                                       44210
C     TITDX=  MAXIMUM ITD ALLOWED                                       44220
C     RNGMN=  MINIMUM VALUE OF RANGE                                    44230
C     RNGMX=  MAXIMUM VALUE OF RANGE                                    44240
C     TOL=    CONVERGENCE TOLLERANCE - PERCENT WITHIN WHICH OBJECTIVE   44250
C             FUNCTIONS MUST AGREE -(DECIMAL)                           44260
C     ALF=    EXPANSION FACTOR FOR BOX METHOD                           44270
C     DELT=   DECIMAL PERCENTAGE OF DISTANCE FROM EXPLICIT              44280
C             CONSTRAINT TO CENTROID TO MOVE WHEN                       44290
C             VIOLATION OCCURRS                                         44300
C     ITRMX=  MAXIMUM NUMBER OF ITERATIONS ALLOWED                      44310
C     NITR=   NUMBER OF CONSECUTIVE ITERATIONS THAT OBJECTIVE FUNCTIONS 44320
C             MUST AGREE                                                44330
C     N=      NUMBER OF INDEPENDENT VARIABLES                           44340
C     NP=     NUMBER OF PASSES                                          44350
C     NTR=    NUMBER OF ROWS                                            44360
C     TNMIN=  MINIMUM NUMBER OF TUBES(BASED ON HIGH VELOCITY)           44370
C     TNMAX=  MAXIMUM NUMBER OF TUBES(BASED ON LOW  VELOCITY)           44380
C     TSAT=   SATURATION TEMPERATURE OF STEAM                           44390
C     COSTT=  VALUE OF OBJECT FUNCTION                                  44400
C     X=      VALUE OF THE INDEPENDENT VARIABLES                        44410
C     XC=     VALUE OF THE CENTROIDS                                    44420
```

```
C     VAMAX=  MAXIMUM AIR VELOCITY - FT/MIN                             44430
C     VAMIN=  MINIMUM AIR VELOCITY - FT/MIN                             44440
C     VWMAX=  MAXIMUM WATER VELOCITY - FT/SEC                           44450
C     VWMIN=  MINIMUM WATER VELOCITY - FT/SEC                           44460
C     CPW=    SPECIFIC HEAT OF WATER                                    44470
C     CPA=    SPECIFIC HEAT OF AIR                                      44480
C     DENW=   DENSITY OF WATER                                          44490
C     DENA=   DENSITY OF AIR                                            44500
      COMMON/EPA/TNMIN,TNMAX,TSAT(21),COSTT(21),X(10,21),XC(10),VAMAX,  44510
     1VAMIN,VWMAX,VWMIN,XN,XP,SUBCL,QMIN,QMAX,PITCH,DIA,                44520
     2RNGMX,RNGMN,TLMIN,TLMAX,TITDX,TITDN                               44530
     3,TSATA,TSATZ,XHEAT(21)                                            44540
      COMMON/SCOND/TTDMN,TTDMX,TISUM(21)                                44550
      COMMON NFO,KGO,KNTR0,KNTR1,NSUM,NPAGE,DAY(2),PI                   44560
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP, 44570
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)44580
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,    44590
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT             44600
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,     44610
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,44620
     2Q(2),QOUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)44630
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),    44640
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)                     44650
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,  44660
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2), 44670
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,  44680
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA                        44690
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF, 44700
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),  44710
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),44720
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)       44730
      COMMON/PASIT/TBUCK                                                44740
      COMMON/TRACE/SSSUM(9),IISUM(3)                                    44750
      DIMENSION XLOW(10),XHIGH(10)                                      44760
C                                                                       44770
C     SET NUMBER OF POINTS IN COMPLEX,KN                                44780
C                                                                       44790
      KN=2*N+1                                                          44800
      ICHCK=0                                                           44810
      NSUM=1                                                            44820
      LJCNT=0                                                           44830
      IISUM(1)=0                                                        44840
      IISUM(2)=1                                                        44850
      IISUM(3)=1                                                        44860
      TBUCK=0.                                                          44870
      ITR=0                                                             44880
      JHIGH=0                                                           44890
      ITRCT=0                                                           44900
      LJ=1                                                              44910
      J=1                                                               44920
```

```
C
C     SET UP ORIGINAL COMPLEX,DETERMINE OBJECT FUNCTIONS
C     AND FIND J,THE POINT WITH THE HIGHEST VALUE
C
      CALL SETUP(J,KN,LJ)
      ITRCT=1
      LJSTR=LJ
C *** LIMIT THE NUMBER OF OUTPUT PAGES TO 200
      IF(NPAGE.GE.200) GO TO 312
  100 MULT=1
C
C     IF HIGHEST POINT,J, HAS REPEATED THEN MOVE J 1/2 THE
C     DISTANCE TO THE CENTROID
C
      IF(J.NE.JHIGH) GO TO 200
      MULT=0
C
C     IF THE SAME POINT HAS BEEN MOVED TOWARDS THE CENTROID 5 TIMES, IT
C     IS ALMOST EQUAL TO THE CENTROID. THUS THE CENTROID IS EITHER THE
C     WORST CASE OR VIOLATES THE IMPLICIT CONSTRAINTS. SET WORST POINT
C     EQUAL TO BEST POINT.
C
  150 IF(ICC.LT.5) GO TO 175
      DO 160 M=1,N
      X(M,J)=X(M,LJ)
  160 CONTINUE
      ICC=0
      GO TO 305
  175 CALL MOVIT(N,J)
      ICC=ICC+1
      GO TO 305
C
C     CALCULATE CENTROIDS OF ALL POINTS EXCEPT J IF J HAS
C     NOT REPEATED AS THE HIGHEST POINT
  200 CALL CENT(J,N,KN,JHIGH)
C
C     IF HIGHEST POINT,J, HAS NOT REPEATED THEN MOVE
C     J IN THE NORMAL FASHION
C
      ICC=0
      JHIGH=J
      TBUCK=COSTT(J)
      DO 300 IX=1,N
      X(IX,J)=XC(IX)+ALF*(XC(IX)-X(IX,J))
  300 CONTINUE
  305 CONTINUE
C
C     CHECK TO SEE IF NEW POINT SATISFIES CONSTRATINTS
C
      CALL CONST(J,DELT)
```

```
C
C     CALCULATE OBJECT FUNCTION FOR NEW POINT
C
  310 CONTINUE
      IISUM(1)=ITRCT
      IISUM(2)=LJ
      IISUM(3)=J
      CALL COSTER(J,VAIR,VH2O,KKILL)
C *** LIMIT THE NUMBER OF OUTPUT PAGES TO 200
      IF(NPAGE.LT.200) GO TO 315
  312 WRITE(6,7)
      GO TO 1000
C
C     IF WATER VELOCITY IS NOT BETWEEN MIN AND MAX FT/SEC, SET
C     NUMBER OF TUBES SUCH THAT WATER VELOCITY IS ON BOUNDARY.
C
  315 IF(KKILL) 380,380,317
  317 GO TO(319,320,340,345) KKILL
  319 V=VWMAX
      GO TO 330
  320 V=VWMIN
  330 X(5,J)=VH2O/V*X(5,J)
      GO TO 310
C
C     IF AIR VELOCITY IS NOT BETWEEN MIN AND MAX FT/MIN, SET TUBE
C     LENGTH SUCH THAT AIR VELOCITY IS ON BOUNDARY. IF DOING THAT
C     VIOLATES TUBE LENGTH CONSTRAINT, MOVE THE POINT 1/2 THE
C     DISTANCE TO THE CENTROID
C
  340 V=VAMAX
      GO TO 350
  345 V=VAMIN
  350 TL=VAIR/V*X(4,J)
      IF(TL.GT.TLMAX.OR.TL.LT.TLMIN) GO TO 150
      X(4,J)=TL
      GO TO 310
  380 LJ=LJSTR
      J=JHIGH
C
C     FIND LOWEST OBJECT POINT,LJ, AND HIGHEST
C     OBJECT POINT,J
C
      DO 600 I=1,KN
      IF(COSTT(I).GT.COSTT(J)) GO TO 400
      IF(COSTT(I).LT.COSTT(LJ)) GO TO 500
      GO TO 600
  400 J=I
      GO TO 600
  500 LJ=I
  600 CONTINUE
```

```
      ITRCT=ITRCT+1
C *** IF LOW POINT REPEATS FOR 15 ITERATIONS NO PROGRESS IS BEING
C *** MADE. THE OBJECT FUNCTION GRADIENT IS FLAT. TRY TO INCREASE
C *** ALF SO AS TO THROW SOLUTIONS OUT OF THE FLAT REGION.
      IF(LJSTR.NE.LJ) GO TO 660
      IF(LJCNT.GT.15) GO TO 640
      LJCNT=LJCNT+1
      GO TO 690
  640 ALF=ALF*1.05
      GO TO 670
  660 LJSTR=LJ
  670 LJCNT=0
  690 CONTINUE
C
C     SEE IF LOW AND HIGH OBJECT POINTS ARE
C     WITHIN CONVERGENCE TOLERANCE
C
      IF((COSTT(J)/COSTT(LJ)-1.).LE.TOL) GO TO 700
C
C
      IF(ICHCK)692,692,698
  692 IF(COSTT(J)/COSTT(LJ)-TOL-1.005)694,694,698
  694 ICHCK=1
      DO 696 IVAR=1,N
      XLOW(IVAR)=X(IVAR,1)
      XHIGH(IVAR)=X(IVAR,1)
      DO 696 IPT=2,KN
      IF(X(IVAR,IPT).LT.XLOW(IVAR))XLOW(IVAR)=X(IVAR,IPT)
      IF(X(IVAR,IPT).GT.XHIGH(IVAR))XHIGH(IVAR)=X(IVAR,IPT)
  696 CONTINUE
      TSATA=AMAX1(TSATA,XLOW(1))
      TSATZ=AMIN1(TSATZ,XHIGH(1))
      TITDN=AMAX1(TITDN,XLOW(2))
      TITDX=AMIN1(TITDX,XHIGH(2))
      RNGMN=AMAX1(RNGMN,XLOW(3))
      RNGMX=AMIN1(RNGMX,XHIGH(3))
      TLMIN=AMAX1(TLMIN,XLOW(4))
      TLMAX=AMIN1(TLMAX,XHIGH(4))
      TNMIN=AMAX1(TNMIN,XLOW(5))
      TNMAX=AMIN1(TNMAX,XHIGH(5))
      TTDMN=AMAX1(TTDMN,XLOW(6))
      TTDMX=AMIN1(TTDMX,XHIGH(6))
  698 CONTINUE
C
C     SET CONSECUTIVE ITERATION COUNTER BACK TO ZERO
C     IF A NEW POINT CAME OUT LOW ENOUGH TO CAUSE TOL VIOLATION
C
      IF(JHIGH.EQ.LJ) ITR=0
      GO TO 800
C
```

```
C     SEE IF NUMBER OF SUCCESSFUL CONSECUTIVE ITERATIONS
C     EQUALS THE NUMBER REQUIRED
C
  700 IF(NITR.GT.ITR) GO TO 725
      IF(COSTT(J).GT.TBUCK)GO TO 100
C *** CALL COSTER AGAIN TO MAKE AC1 PRINT OUT THE DESIGN WITH
C *** THE LOWEST COST FUNCTION. SET KNTR1 TO KILL OFF-DESIGN PERFORMANCE
      KNTR1=1
      SUBCL=X(6,LJ)
      CALL COSTER(LJ,VAIR,VH2O,KKILL)
      GO TO 750
C *** INCREMENT THE CONSECUTIVE ITERATION COUNTER IF A NEW POINT
C *** IS TO BE WORKED ON NEXT
  725 IF(J.NE.JHIGH) ITR=ITR+1
      GO TO 800
C
C     SET MULT=2 TO PRINT LAST ITERATION
C
  750 MULT=2
      NSUM=KN
      GO TO 1000
C
C     SEE IF MAXIMUM NUMBER OF ITERATIONS HAS BEEN EXCEEDED
C
  800 IF(ITRCT.GE.ITRMX)  GO TO 900
      IF(MULT.EQ.2) GO TO 1000
      GO TO 100
  900 WRITE(6,6)
C
C     PRINT LAST ITERATION
C
      GO TO 750
 1000 CONTINUE
    6 FORMAT(/,62H BOX METHOD DID NOT CONVERGE IN SPECIFIED NUMBER OF IT
     1ERATIONS)
    7 FORMAT(///,38H  PROGRAM EXCEEDED 200 PAGES OF OUTPUT)
      RETURN
      END
      SUBROUTINE MOTOR(NMOT,MORPM,HPMOT,CMOT1,CTMOT)
C
C *** THIS SUBROUTINE CALCULATES THE COST FOR PURCHASING A MOTOR
C
C *** INPUT VARIABLES ***
C     MORPM = MOTOR RPM
C     HPMOT = MOTOR HORSEPOWER
C
C *** OUTPUT VARIABLE ***
C     CMOT1 = MOTOR COST ($)
C
      ZMOT=NMOT
C
      INDEX=MORPM/900
      GO TO (1200,1800,2700,3600),INDEX
C
 1200 CMOT1=10.827*HPMOT+197.325
      GO TO 1
 1800 CMOT1=9.777*HPMOT+188.57
      GO TO 1
 2700 CONTINUE
 3600 CMOT1=6.627*HPMOT+162.3
C
    1 CONTINUE
      CTMOT=ZMOT*CMOT1
C *** ADD 10 PCT. FOR SHIPPING TO MANUFACTURER
      CTMOT=1.1*CTMOT
C
C
      RETURN
      END
```

```
      SUBROUTINE MOVIT(N,J)
      COMMON/EPA/TNMIN,TNMAX,TSAT(21),COSTT(21),X(10,21),XC(10),VAMAX,
     1VAMIN,VWMAX,VWMIN,XN,XP,SUBCL,QMIN,QMAX,PITCH,DIA,
     2RNGMX,RNGMN,TLMIN,TLMAX,TITDX,TITDN
C
C     THIS SUBROUTINE MOVES POINT J 1/2 THE DISTANCE
C     TO THE CENTROID
C
      DO 100 I=1,N
      X(I,J)=(X(I,J)+XC(I))/2.
```

```
  100 CONTINUE
      RETURN
      END
```

```
      SUBROUTINE MTDOV (TDT,NP,NR,MSW,CMIX,KER,PA,R1,XNTU1,LPMT,TMTD,FT,
     1 COCUR)
C *** CALCULATION OF LMTD, NTU, F, R, AND P.
C *** CMIX=1 ASSUME UNMIXED-UNMIXED. IF CMIX=0 THEN MIXED-UNMIXED.
      DIMENSION XNR(10),PNR(10),TB(20)
C *** SET TO MATRIX OF N X N
      SN=.1
      ZNTP=NP
   12 P=PA*R1
      R=1.0/R1
   63 IF (P-1.0) 70,64,64
   64 KER=70
      GO TO 482
C *** IF R CLOSE TO ONE CORRECT EQ.
   70 IF (ABS(R-1.0)-.001) 72,80,80
   72 DELT=P/(1.0-P)
      GO TO 90
C *** DELT IS THE NTU FOR TRUE COUNTERCURRENT FLOW
   80 DELT=ALOG((1.0-P)/(1.0-P*R))/(R-1.0)
   90 CONTINUE
   92 CONTINUE
C *** NEWTON RAPHSON CONVERGENCE TECHNIQUE STARTS HERE
  100 XNR(1)=.1
      XNR(2)=DELT
  120 LPMT=1
  130 XNTU=XNR(LPMT)
C *** MULTIPLE PASS CORRECTION
  140 XNTA=XNTU/ZNTP
C *** UNMIXED-UNMIXED RELATIONS,1 PASS - AFTER STEVENS - 20X20 MATRIX
  180 XNTA=XNTA*SN
      XR=XNTA/(1.0+.5*(1.0+R)*XNTA)
      TH2=0.0
      DO 182 I=1,10
  182 TB(I)=0.0
      DO 200 J=1,10
      DO 190 I=1,10
      IF (I-1) 184,184,186
  184 TA=1.0
  186 DT=(TA-TB(I))*XR
      TA=TA-DT
  190 TB(I)=TB(I)+DT*R
  200 TH2=TH2+TA*SN
      PN=1.0-TH2
  206 IF (NP-2) 210,260,260
  210 PNR(LPMT)=P-PN
C *** CALL N/R CONV. S/R
  220 CALL NRCON (LPMT,XNR,PNR,KER,71,1.E-4,K,10)
      IF (K-1) 130,400,500
C *** CORRECT ONE PASS P FOR ANY NUMBER OF PASSES
  260 CONTINUE
  262 IF (ABS(R-1.0)-0.001) 270,270,280
  270 PN=(ZNTP*PN)/(1.0+(ZNTP-1.0)*PN)
      GO TO 210
  280 PN=((1.0-PN*R)/(1.0-PN))**NP
      PN=(PN-1.0)/(PN-R)
      GO TO 210
  400 CONTINUE
  450 TMTD=TDT*P/XNTU
  482 PA=P*R
  490 R1=1.0/R
  500 RETURN
      END
```

```
      SUBROUTINE NOZCT (DNZI,DNZ,WNZ,VNZ,DEN,PNZMX,DPNZ,DBW,CTPA,I)
C *** CONTROLS SIZING OF TUBE SIDE NOZZLES
      COMMON/PIPE/XDIA(20),XLGT(20),NN1,NN2,XTOWR,PLNMH,TTTBH,VX,VN,VAVE
      DIMENSION DNZI(1),DNZ(1),VNZ(1),DPNZ(1),DEN(4),VKTN(2)
      DATA VKTN/1.0,0.5/
      DPMAX=.1
      IF (DNZI(I)-.01) 20,20,30
   20 IF (I-1) 22,22,120
C *** ESTIMATE NOZZLE SIZE FROM AVERAGE ALLOWABLE WATER VELOCITY
   22 DNZ(I)=.4*SQRT(WNZ/(VAVE*DEN(I)*3.14159))
      CALL NOZID (CTPA,DBW   ,DNZ(I),N,      DNZMX,0)
   30 VNZ(I)=WNZ       *.04/(.7854*DNZ(I)**2*DEN(I))
      RV2N=DEN(I)*VNZ(I)**2
      DPNZ(I)=VKTN(I)*RV2N/(144.0*64.34)
   60 IF (DNZI(I)-.01) 70,200,200
   70 IF (DPNZ(I)    -DPMAX) 200,200,100
  100 IF (DNZ(I)-DNZMX+.01) 105,200,200
  105 N=N+1
      CALL NOZID (CTPA,DBW,DNZ(I),N,DNZMX,1)
      GO TO 30
C *** IF DENSITIES ARE WITHIN 15 PCT. LET OUTLET =INLET
  120 IF(ABS(DEN(2)/DEN(1)-1.)-.15)140,140,22
  140 DNZ(I)=DNZ(I-1)
      GO TO 30
  200 RETURN
      END
```

```
      SUBROUTINE NOZID (CTPA,DBW,DNZ,N,DNZMX,KSTEP)
      DIMENSION DNZA(20)
      DATA DNZA/1.049,2.069,3.068,4.026,5.047,6.065,8.071,10.136,12.09,
     1          13.25,15.25,17.25,19.25,21.25,23.25,25.25,29.25,33.25,
     2          35.25,41.0/
      NMAX=20
C *** LOOK UP ON NOZZLE SIZE
      IF (KSTEP-1)  5,45,45
    5 X=0.8*DBW/(1.0+CTPA)
   30 DNZMX=X*DBW
C *** CHECK IF PIPE DIAMETER IS ALREADY TOO LARGE FOR TABLE
      IF(DNZ-DNZA(NMAX)/.97)31,31,41
   31 DO 40 J=1,NMAX
      N=J
      IF (DNZA(N)/DNZ-.97) 40,50,50
   40 CONTINUE
C *** LET PIPE GO UP BY INCREMENTS OF 6 INCHES TO A MAXIMUM OF 15 FEET
   41 DNZY=42.
      DO 43 J=1,21
      IF(DNZY/DNZ-.97)42,44,44
   42 DNZY=DNZY+6.
   43 CONTINUE
   44 DNZ=DNZY
      GO TO 90
   45 IF (N-NMAX) 50,60,60
   50 DNZ=DNZA(N)
      GO TO 70
   60 DNZ=DNZ+4.0
   70 IF (DNZ-DNZMX) 90,90,80
   80 DNZ=DNZMX
   90 RETURN
      END
      SUBROUTINE NOZZLE(DTNOZ,CTNOZ1)
C
C *** THIS SUBROUTINE GIVES THE INFORMATION OF INSTALLING COST
C *** FOR A CARBON STEEL NOZZLE WITH WELD NECK FLANGE
C *** PRESSURE  150 PSI
C *** NOMINAL DIAMETER  2.4 --- 24.2 INCH
C
C
C *** INPUT VARIABLE ***
C     DTNOZ = NOMINAL NOZZLE DIAMETER (INCH)
C
C *** OUTPUT VARIABLE ***
C     CTNOZ1 = COST FOR INSTALLING ONE NOZZLE ($)
C
      CTNOZ1=0.
      IF(DTNOZ.LT..001)GO TO 50
      IF (DTNOZ.GT.24.2) GO TO 40
C
C  $  NOMINAL DIAMETER IN RANGE 13.8-- 24.2 INCH
      IF (DTNOZ.LE.13.8) GO TO 10
      CTNOZ1=168.0+21.73*(DTNOZ-13.8)
      GO TO 50
C
C  *  NOMINAL DIAMETER IN RANGE  8.2 -- 13.8 INCH
   10 IF (DTNOZ.LE.8.2) GO TO 20
      CTNOZ1=78.0+16.07*(DTNOZ-8.2)
      GO TO 50
C
C  *  NOMINAL DIAMETER IN RANGE 2.4 -- 8.2 INCH
   20 IF (DTNOZ.LT.2.4) GO TO 30
      CTNOZ1=16.0+10.69*(DTNOZ-2.4)
      GO TO 50
C
   30 WRITE(6,34)
   34 FORMAT(1H ,*NOZZLE DIAMETER TOO SMALL FOR COST ESTIMATION*)
      GO TO 50
C
   40 WRITE(6,45)
   45 FORMAT(1H ,*NOZZLE DIAMETER TOO LARGE FOR COST ESTIMATION*)
C
   50 CONTINUE
      RETURN
      END
      SUBROUTINE NRCON (NR,X,Y,KER,KERNO,TOL,KODE,NX)
C *** NEWTON-RAPHSON PROCEDURE
      DIMENSION X(1),Y(1)
C *** IF KODE=0,1,2 THEN CONTINUE, CONVERGED, ERROR EXIT RESP.
C *** IF KODE IS SET TO 100 FROM OUTSIDE  THEN
C *** NEGATIVE VALUES OF X ARE ALLOWED
      IF (ABS(Y(NR))-TOL) 10,10,20
   10 KODE=1
      GO TO 100
   20 IF (NR- 1) 90,90,30
   30 IF (NR-NX) 50,40,40
   40 KODE=2
   46 KER=KERNO
      GO TO 100
   50 IF (ABS(Y(NR)/Y(NR-1)-1.0)-1.E-8) 53,53,54
   53 X(NR+1)=(X(NR)+X(NR-1))*.5
      GO TO 1000
   54 X(NR+1)=X(NR)-Y(NR)*(X(NR)-X(NR-1))/(Y(NR)-Y(NR-1))
 1000 IF(NR-3)66,55,55
   55 J1=0
      J2=0
      Y1=-1.E6
      Y2=+1.E6
      DO 60 JJ=1,NR
      IF (Y(JJ)    ) 56,56,57
   56 IF (Y(JJ)-Y1) 60,58,58
   57 IF (Y(JJ)-Y2) 59,59,60
   58 Y1= Y(JJ)
      J1=   JJ
      GO TO 60
   59 Y2= Y(JJ)
      J2=   JJ
   60 CONTINUE
C *** SET LOK=1 WHEN THE Y RETURNED IS NO LONGER BETWEEN Y1 AND Y2
      LOK=0
      IF(Y(NR)-Y1+1.E-8)1250,1200,1200
 1200 IF(Y(NR)-Y2-1.E-8)1275,1275,1250
 1250 LOK=1
 1275 CONTINUE
      IF (J1) 66,66,61
   61 IF (J2) 66,66,62
   62 IF (X(NR+1)-X(J1)) 64,65,63
C *** CHECKS MADE HERE TO DETERMINE IF NEW GUESS IS BETWEEN THE BEST
C *** TWO PRIOR GUESSES WHICH WERE NEG. AND POS.
   63 IF(X(NR+1)-X(J2))1100,65,65
   64 IF(X(NR+1)-X(J2))65,65,1100
C *** IF NEW GUESS IS TOO CLOSE TO PRIOR GUESS THEN USE AVG. INSTEAD
C *** OF NEWTON-RAPHESON EQ. AT 66 BELOW
 1100 IF(ABS(X(NR+1)/X(NR)-1.0)-TOL*0.1)1110,1110,66
 1110 IF(ABS(X(NR)/X(NR-1)-1.0)-TOL*0.1)1120,1120,66
```

```
C *** IF GUESSES ARE TOO CLOSE AND LOK=1 THEN ASSUME CONVERGENCE
 1120 IF(LOK-1)65,10,10
C *** EQ. BELOW USES AVG. OF TWO GUESSES WHICH PRODUCED THE
C *** CLOSEST NEG. AND POSIT. ERRORS
   65 X(NR+1)=(X(J1)+X(J2))*.5
   66 IF (KODE-100) 67,80,67
   67 IF (X(NR+1) ) 70,70,80
   70 X(NR+1)=X(NR)*.5
C *** SKIP CHECK IF X(NR-1) IS ZERO
   80 IF(ABS(X(NR-1))-1.E-20)90,90,82
   82 IF(ABS(X(NR)/X(NR-1)-1.0)-TOL*1.E-6)84,84,90
   84 KODE=3
      GO TO 46
   90 KODE=0
      NR=NR+1
  100 RETURN
      END
```

```
      SUBROUTINE OCONV(KODE,KODE1)
C *** OUTPUT UNIT CONVERSION
C *** KODE=1   CONVERT FROM INTERNAL TO U.S. UNITS
C *** KODE=2   CONVERT FROM INTERNAL TO S.I. UNITS
C *** KODE=3   CONVERT FROM U.S. TO INTERNAL UNITS
C *** KODE=4   CONVERT FROM S.I. TO INTERNAL UNITS
      COMMON IDUM(6),RDUM(3),IDUMW(34),DUMW(246),DUMYD(60),DUM(912)
      IF(KODE-2)100,100,300
C *** INTERNAL TO U.S.
  100 DUMW(86)=DUMW(86)*27.73
      DUMW(79)=DUMW(79)*27.73
      DO 110 LL=149,155
  110 DUMW(LL)=DUMW(LL)*1.E-3
      DUMW(151)=DUMW(151)*1.E3
      DO 120 LL=101,102
  120 DUMW( LL)=DUMW( LL)*1.E-6
      DO 130 LL=108,124
  130 DUMW( LL)=TCONV(DUMW(LL),1,2)
      GO TO 900
C *** U.S. TO INTERNAL
  300 DUMW(86)=DUMW(86)/27.73
      DUMW(79)=DUMW(79)/27.73
      DO 310 LL=149,155
  310 DUMW(LL)=DUMW(LL)*1.E3
```

```
      DUMW(151)=DUMW(151)*1.E-3
      DO 320 LL=101,102
  320 DUMW( LL)=DUMW( LL)/1.E-6
      DO 330 LL=108,124
  330 DUMW( LL)=TCONV(DUMW(LL),1,1)
      GO TO 900
  900 RETURN
      END
```

```
      SUBROUTINE OUTFA (KOT,KOT1)
C *** FINAL PRINTOUT (PART-1)
      DIMENSION UUTEM(2,2),UUMF(3,2),UUPRA(2,2),UUPR(2,2),UUDRT(2,3),
     1UUDIR(3,3),ISIZE(3),BARR(3)
      COMMON NFO,KGO,KNTRO,KNTR1,NM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/CASED/BARB(13)
C *** DATA FOR OUTPUT ALPHANUMERIC INFO.
      DATA UUTEM/4H(DEG,4H.F) ,4H(DEG,4H.C) /,
     3 UUMF/3H(M-,3HLB/,3HHR),3H   ,3H(KG,3H/S)/, UUPRA/3H(PS,3HIA),
     43H(K-,3HPA)/,UUPR/3H (P,3HSI),3H(K-,3HPA)/
      DATA UUDRT/4H FOR,3HCED,4HINDU,3HCED,4HNATU,3HRAL/,
     1 UUDIR /2HHO,4HRIZO,4HNTAL,2H  ,4HINCL,4HINED,2H  ,4HVERT,4HICAL/,
     1BARR/4HCOND,4HEN.W,4HATER/
 1100 FORMAT(72H1** PRINTOUT OF OPTIMUM DESIGN GENERATED BY THE PFR OPTI
     1MIZATION PROGRAM,/)
 1105 FORMAT(4H ---,17(4H----))
```

```
1110 FORMAT( 8H  1 SIZE,I3,1H-,I4,1H-,I2,1H-,A2,2A4,1X,A4,A3,
    15H NBU=,I3,6H I     ,4A5,/,25H  2 SURFACE/UNIT EXT/BARE,F11.0,1H/,
    2F9.0,11H I SITE    , 3A5,/,25H  3 HEAT EXCHANGED / MTD ,F11.4,
    31H/,F6.2,3X,11H I TURBINE ,3A5,/,25H  4 RATE EXT/BARE/CLEAN  ,
    4F7.2,1H/,F6.2,1H/,F6.2,11H I CONDENSR,3A5)
1120 FORMAT(47H ** TUBE SIDE  **     ** PROCESS AND PERFORMANCE,
    117H DATA PER UNIT **,/,20H  5 FLUID CIRCULATED,8X,3A4,10X,
    222HENTERING          LEAVING,/,15H  6 TOTAL FLUID,15X,3A3,F19.3,/,
    312H  7    LIQUID,18X,3A3,5X,2F14.3)
1130 FORMAT(15H  8 TEMPERATURE,17X,2A4,4X,2(5X,F9.1),/,
    133H  9 PRESSURE                     ,2A3,11X,F8.1,F14.1,/,
    233H 10 PRESSURE DROP SPEC./CALC.    ,2A3,12X,F7.2,1H ,F13.2,/,
    32H -,35(2H--))
     KFI=2
     NBUT=ZBUS*ZBUP*ZBYP+0.01
     IF (ANG(1)-0.27) 4,5,5
   4 KANG=1
     GO TO 8
   5 IF (ANG(1)-1.47) 6,6,7
   6 KANG=2
     GO TO 8
   7 KANG=3
   8 CONTINUE
     ISIZE(1)=(DBW+4.0)/12.0+0.5
     ISIZE(2)=NTT
     ISIZE(3)=NTR
 220 CONTINUE
 400 WRITE(NFO,1100)
     WRITE(NFO,1105)
     WRITE(NFO,1110) (ISIZE(I),I=1,3),(UUDIR(I,KANG),I=1,3),
    1 (UUDRT(I,KFI),I=1,2),NBUT,(BARB(I),I=1,4),ASTOT,ABARE,
    2(BARB(I),I=5,7),QDUT,TMTD,(BARB(I),I=8,10),UTOT,UBARE,UCLN,
    3(BARB(I),I=11,13)
     WRITE(NFO,1105)
     WRITE(NFO,1120)(BARR(I),I=1,3),(UUMF(I,KOT),I=1,3),W(1),
    1(UUMF(I,KOT),I=1,3),WLQ(1),WLQ(2)
     WRITE(NFO,1130)(UUTEM(I,KOT),I=1,2),TIN(1),TOUT(1),
    1(UUPRA(I,KOT),I=1,2),PTUB,POUT(1),(UUPR(I,KOT),I=1,2),PSD,DPTOT(1)
 500 RETURN
     END
```

```
      SUBROUTINE OUTFB (KOT,KOT1)
C *** FINAL PRINTOUT (PART-2)
      DIMENSION AOUT1(5,2),AOUT2(5,2)
      DIMENSION UUAR(2,2),UUTEM(2,2),UUPR(2,2),UUAFR(2,2),
     1 UUDP(2,2),UUSV(2,2),UUL1(2),UUL2(2),UUFLX(3,2),UUMF(3,2),
     2UUPWR(2,2),UUHDR(2,5),UULAY(2,2),UUTUB(2,2),UUL3(2),UUFIN(2,3),
     3UOTYP(3,3)
      COMMON NFO,KGO,KNTR0,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QOUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/FAN/EFFAN,NBLAD,HPMSP
C *** DATA FOR OUTPUT ALPHANUMERIC INFO.
      DATA AOUT1/4H   S,4HTATI,4HC D.,4HP.,C,4HALC.,
     1           4H   D,4HRAFT,4H HEA,4HD,RE,4HQD. /,
     2     AOUT2/4H   S,4HTATI,4HC D.,4HP.,S,4HPEC.,
     3           4H   D,4HRAFT,4H HEA,4HD,AV,4HAIL./
      DATA UUAR/3H(FT,2H2),3H (M,2H2)/,
     1  UUTEM/4H(DEG,4H.F) ,4H(DEG,4H.C) /,
     2UUAFR/3H(AC,3HFM),3H(M3,3H/S)/,
     4 UUPR/3H (P,3HSI),3H(K-,3HPA)/,UUMF/3H(M-,3HLB/,3HHR),3H   ,3H(KG,
     5 3H/S)/
      DATA UUDP/4H(IN-,4HH2O),4H(K-P,4HA)  /, UUSV/3H(SF,3HPM),
     1 3H (M,3H/S)/, UUL1/4H(FT),4H (M)/, UUL2/4H(IN),4H(MM)/,
     2 UUFLX/4H (LB,4H/HR-,4HFT2),4H   (,4HKG/S,4H-M2)/,
     3UUPWR/3H (H,3HP) ,
     4 3H (K,3HW) /, UUL3/3HIN.,3H M./
      DATA UUHDR/4H    ,4HPLUG,4H   C,4HOVER,4H  BO,4HNNET,4HWELD,4H-BOX
     1,4HMANI,4HFOLD/, UULAY/4HSTAG,4HGERD,4H IN-,4HLINE/, UUTUB/4H   P,
     24HLAIN,4H  FI,4HNNED/,
     3 UUFIN/ 4H  SM,4HOOTH,4H SLO,4HTTED,4HSERR,4HATED/,
     4 UOTYP /4H    ,4HSTRA,4HIGHT,4H    ,4H  U-,4HTUBE,4H  SE,
     5 4HRPEN,4HTINE/
 1170 FORMAT(23H0** PROGRAM MESSAGES - ,10(I3,1H,))
 1175 FORMAT(15H ** AIR SIDE **,/,13H 11 AIR/UNIT ,3A3,F11.2,8H   TEMP.,
     110H IN/OUT   ,2A4,F6.1,1H/,F6.1,/,11H 12 AIR/FAN,5X,2A3,F11.2,
     212H   ALTITUDE ,9X,A4,7X,F7.0,/,16H 13 FACE VEL    ,2A3,F11.3,5A4,
     32X,2A4,F9.4,/,10H 14 MASS V,3A4,F11.3,5A4.2X.2A4.F9.4)
 1176 FORMAT(2H -,35(2H--))
 1180 FORMAT(54H ** CONSTRUCTION INFO. PER BUNDLE   DESIGN PRESSURE   ,
     12A3,F12.1,/,18H 15 BUNDLE WIDTH  ,A4,4X,F7.2,18H   NO. TUBE ROWS
     2,I3,15H  TUBE PASSES  ,I3,/,22H 16 NO. BUNDLES PARA  ,I2,7H SERIES
     3,I2,27H   TUBE INCLINATION  (DEG.),3X,F9.1,/,16H 17 NO. BAYS    ,
     45HPARA ,I3,7H SERIES,I2,14H   HEADER TYPE,17X,2A4)
 1190 FORMAT(/,31H ** TUBE AND FIN INFORMATION **,/,14H 18 NO. TUBES/,
     16HBUNDLE,7X,I6,12H   TUBE TYPE,3X,3A4,4X,2A4,/,14H 19 TUBE OD/ID,
     23X,A4,F6.3,1H/,F5.3,14H   TUBE LAYOUT,F5.0,8H DEGREES,4X,2A4,/,
     317H 20 FIN OD/THICK ,A4,F6.3,1H/,F5.3,23H   PITCH- TRANSVERSE   ,
     4A4,F12.4,/,18H 21 NO. FINS PER  ,A3,5X,F7.2,8X,15H- LONGITUD.    ,
     5A4,F12.4)
 2000 FORMAT(21H 22 TUBE LENGTH-OVRL ,A4,F8.3,17H   FINNING FACTOR,F22.3
     1,/,3H 23,12X,6H-EFF. ,A4,F8.3,14H   FIN SURFACE,17X,2A4,/,4H 24 ,
     217HTUBE SHEET THICK.,A4,F8.1,23H   TOTAL SPACER LENGTH ,A4,F12.1)
 2010 FORMAT(/,20H ** FAN EQUIPMENT **,/,16H 25 NO. FANS/BAY,14X,I3,
     118H   POWER/FAN,(EFF=,F3.2,1H),2A3,F11.2,/,16H 26 FAN DIAMETER,5X,
     2A4,F8.3,22H   POWER/FAN,SPEC.    ,2A3,F11.2,/,16H 27 AREA RATIO- ,
     311H   FAN/FACE,F6.3,12H   PLOT AREA,10X,A3,A2,F12.2,/,9H 28 AREA ,
     418HRATIO- X-SECT/FACE,F6.3,15H   ASPECT RATIO,F24.3)
      KHED=1
      KFIN=2
      KCTL=1
      KCBU=1
      DPI=0.0
      XAOF=(DBW+4.0)/12.0
      NFAN=ZFAN+0.01
      NBUP=ZBUP+0.01
      NBUS=ZBUS+0.01
      NBYP=ZBYP+0.01
C *** FOR NOW SET NUMBER OF BAYS IN SERIES EQUAL TO 1
      NBYS=1
      KFINS=1
      KNAT=1
  200 WRITE(NFO,1175)(UUMF(I,KOT),I=1,3),W(2),(UUTEM(I,KOT),I=1,2),
     1 TIN(2),TOUT(2),(UUAFR(I,KOT),I=1,2),WAPF,UUL1(KOT),VISLZ(2),
     2 (UUSV(I,KOT),I=1,2),VAPP,(AOUT1(K,KNAT),K=1,5),(UUDP(I,KOT),I=1,2
     3),DPTOT(2),(UUFLX(I,KOT),I=1,3),GAMAX,(AOUT2(K,KNAT),K=1,5),
     4 (UUDP(I,KOT),I=1,2),DPI
      WRITE(NFO,1176)
      WRITE(NFO,1180)(UUPR(I,KOT),I=1,2),DPTA,UUL1(KOT),XAOF,NTR,NTP,
     1NBUP,NBUS,ANGI,NBYP,NBYS,(UUHDR(I,KHED),I=1,2)
      WRITE(NFO,1190)NTT,(UOTYP(I,KCBU),I=1,3),(UUTUB(I,KFIN),I=1,2),
     1UUL2(KOT),DTO,DTIM,TLA,
     1(UULAY(I,KCTL),I=1,2),UUL2(KOT),DTF,DFT,UUL2(KOT),PT,UUL3(KOT),
     2ZNF,UUL2(KOT),PL
      WRITE(NFO,2000) UUL1(KOT),VISLZ(1),RAOR,  UUL1(KOT),TLTE,
     1(UUFIN(I,KFINS),I=1,2),UUL2(KOT),DLTS,UUL2(KOT),DLSP
```

```
      WRITE(NFO,2010)NFAN,EFFAN,(UUPWR(I,KOT),I=1,2),HPFNC,UUL1(KOT),
     1DFAN,(UUPWR(I,KOT),I=1,2),HPMSP    ,RFNPL,(UUAR(I,KOT),I=1,2),APLOT
     2,RAPMX,RASPC
  430 IF(MM)490,490,440
  440 WRITE (NFO,1170) (KERR(I),I=1,MM)
C *** STORE VALUES FOR SUMMARY OUTPUT
  490 CONTINUE
      IF (KGO-1) 550,550,510
  510 ISUM(01,NSUM)=99
      X=MM
      M=AMIN1(10.0,X)
      ISUM(02,NSUM)=M
      DO 520 I=1,M
  520 ISUM(I+2,NSUM)=KERR(I)
  550 CONTINUE
      NPAGE=NPAGE+1
      RETURN
      END
```

```
      SUBROUTINE OUTPE
C *** ROUTINE CALCULATES THE COMMON VARIABLES NECESSARY FOR OUTPUT
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3SP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/TRACE/SSSUM(9),IISUM(3)
      COMMON/PEN/ATTR(20),DATTR(20),AMBTPT(20),BCAPC,NATTR,CAPCST,CMAIN,
     1MACC,AFCR2,XLVL,FLCST,CAPBS,PLDFT(20),STMCT,CUTMP,SHELP,BHTRT(6)
```

```
      COMMON/FAN/EFFAN,NBLAD,HPMSP
      COMMON/PIPE/XDIA(20),XLGT(20),NN1,NN2,XTOWR,PLNMH,TTTBH,VX,VN
     1,VAVE
      COMMON/JUMP/JAKE,TINMX,NOO2I,DTN2I,NOO1I,NFPIN,NOO2O,NOO1O
      COMMON/CONTL/CSTOR,INML,D(13)
      COMMON/JAN7/DUM(12),IDUM,DUM2(4),PDMAX,DUM3
      ABARE=ASTOT/RAOR
      IF(KNTR1.EQ.0)GO TO 600
  100 TLTE=DLTE/12.0
      IF (KGO-2) 120,110,110
  110 TMTD=0.0
      UBARE=0.0
      GO TO 500
  120 CONTINUE
  160 HTS=RAOI/(1.0/UTOT-(RTOT+RFIN+1.0/HAIR))
  220 CONTINUE
  280 UCLN=RAOR/(1.0/UTOT-RFTOT)
      UBARE=UTOT*RAOR
      XREX=(1.0/FSUM-1.0)*100.0
      J=1
      DO 290 I=1,2
  290 RE12(I,J)=REA(J)*VIS(J)/VIS12(I,J)
      TT2=TOUT(1)
  306 TWALL=TT2-UTOT*RAOI*(TT2-TIN(2))/HTS
  308 TD=1.0/(1.0/HTS+0.5*(RTW-RFI))
      DT1=TIN(1)-TOUT(2)
      TD=TIN(1)-UTOT/TD*DT1
  500 WLQ(1)=W(1)
      WLQ(2)=W(1)
  600 CONTINUE
C *** SET UP VARIABLES AND CALL ACCOST FOR BUNDLE COST
      NBPU=ZBYP+.01
      NMOT=ZFAN+.01
      DHEDW=DBW+4.
      IF((-1)**NTP)710,710,720
  710 DTN1O=0.
      GO TO 730
  720 DTN1O=DNZ(2)
  730 CONTINUE
C
C *** ASSUME VELOCITY ENTERING THE SIDES OF THE BUNDLE EQUALS VAPP
C *** AND CALCULATE THE HEIGHT OF THE TOWER
      XTOWR=W(2)/ZBYP/ZBUP*12./VAPP/DBW/60./.075
C *** FIND 2 OF THE PIPE SIZES TO BE USED IN GEOM2
      D(5)=SQRT(W(1)/DEN12(1,1)/VX/19.635)
      D(9)=D(5)/2.
C *** SET PIPING ARRANGEMENT CODE FOR GEOM2
      INML=1
      IF(D(5).GT.PDMAX)INML=2
      IF(((-1)**NTP).LT.0)INML=INML+2
```

```
C *** ADD 1/2 OF SUPPLY LINE DIAMETER TO TOWER HEIGHT TO INSURE THAT
C *** PIPE DOES NOT SIGNIFICANTLY INTERFERE WITH AIR FLOW
      IF(INML.GT.2)XTOWR=XTOWR+D(9)/24.
      CALL ACCOST(DLTS,NTT,NTR,NTP,DTIM,DTO,NFPIN,PL,PT,DHEDW,DLOV,
     1 DNZ(1),DTN1O,NOO1I,NOO1O,DTN2I,DNZ(2),NOO2I,NOO2O,ZBUP,ZFAN,DFAN,
     2 NBLAD,NMOT,HPFNC,NBPU,XTOWR,KNTR1,CTTOT,CSTOR,DFH,DFT)
      PRICE(1,NSUM)=CTTOT*COST(2)
      STOTS=PRICE(1,NSUM)
  800 CONTINUE
      IF(KNTR1.EQ.0)GO TO 850
C *** TRANSFORM INPUT DATA FOR UNIT CONVERSION
      VISLZ(2)=HALT
      DPTA=PDI
      APLOT=ZBYP*ZBUP*(DLOV+DNZ(1)*.2)*(DBW+4.0)/12.0
C *** CORRECT THE PLOT AREA FOR THE INCLINATION OF THE TUBES
C     ANG(3) IS THE COSINE(ANGI)
      APLOT=APLOT*ANG(3)
  850 CONTINUE
      VISLZ(1)=DLOV
      ISUM(09,NSUM) = ZFAN+0.01
      ISUM(10,NSUM) = ZBYP+0.01
      ISUM(12,NSUM) = NTT
      ISUM(13,NSUM) = DLOV+0.01
      SSUM(03,NSUM) = (DBW+4.0)/12.0
      SSUM(04,NSUM) = DFAN
      SSUM(05,NSUM) = ABARE
      SSUM(08,NSUM) = QDUT*1.E-6
      SSUM(10,NSUM) = VAPP
      SSUM(11,NSUM) = HPFNC
      SSUM(12,NSUM) = TCONV(TOUT(1),1,2)
      SSUM(15,NSUM) = DPTOT(2)*27.73
      SSUM(16,NSUM) = DPTOT(1)
      SSSUM(1)=ASTOT*1.E-03
      SSSUM(2)=TCONV(TIN(1),1,2)
      SSSUM(3)=VT
      SSSUM(4)=W(1)*1.E-06
      SSSUM(5)=TCONV(TIN(2),1,2)
      SSSUM(6)=TCONV(TOUT(2),1,2)
      SSSUM(7)=W(2)*1.E-06
      SSSUM(8)=STOTS
      SSSUM(9)=TIN(1)-TIN(2)
      SSUM(14,NSUM)=(SSSUM(2)-SSUM(12,NSUM))/SSSUM(9)
      ISUM(5,NSUM)=SSSUM(5)+.49
      ISUM(6,NSUM)=SSSUM(6)+.49
      ISUM(3,NSUM)=VAPP+.49
      ISUM(4,NSUM)=SSSUM(2)+.49
      SSUM(1,NSUM)=VT
      SSUM(2,NSUM)=SSSUM(4)
      SSUM(9,NSUM)=SSSUM(7)
      SSUM(7,NSUM)=SSSUM(9)
      RETURN
      END
```

```
      SUBROUTINE OUTPT
C *** CONTROLS THE FINAL AND SUMMARY OUTPUTS AND CALL OPTIM(IZER)
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QOUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLO(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      KOT=1
      KOT1=KOT
  100 CALL OCONV (KOT,1)
      CALL OUTFA (KOT,KOT1)
      CALL OUTFB (KOT,KOT1)
  250 CALL OCONV (KOT+2,1)
  500 CALL OWARN
      CALL SECOND(TYM1)
      TYMEL=TYM1-DAY(2)
      DAY(2)=TYM1
      WRITE(NFO,6000)TYMEL
  610 CALL OUTSM
  700 CONTINUE
 1000 RETURN
 6000 FORMAT(21H0*** CASE EXECUTED IN,F8.2,5H SEC.)
      END
      SUBROUTINE OUTPUT(WTDUM,TTIN,TOUT,CLFAC,VMIN,VMAX,TLMIN,TLMAX,TSAT
     1,QDUM,CITEM,CNEW,NPAGE,DAY,DPMAX,TLM,DPTOT,PSAT,PS1,PS2,KCOND,
     1KMETL,MN,BWG,
     2TS1,TS2,TLM1,TLM2,UO1,UO2,TR1,TR2,FRAC,FRAC2,TIN2,PSMIN,PSMAX)
      DIMENSION CNEW(15),CITEM(10,15)
      DIMENSION TUBEM(13,2),SHETM(6,2)
      DATA TUBEM/7H   ADMI,7H ARSENI,7H   ALUM,7H ALUM. ,7H ALUM. ,
     1 7H  MUNTZ,7H 90/10 ,7H 70/30 ,7H CARBON,7H 410 ST,7H 304 ST,
     2 7H 316 ST,7H   TITA,7HRALTY  ,7HCAL CU ,7HINUM   ,7HBRASS  ,
     3 7HBRONZE ,7H METAL ,7HCU - NI,7HCU - NI,7H STEEL ,7HAINLESS,
     4 7HAINLESS,7HAINLESS,7HNIUM   /
      DATA SHETM/7H  MUNTZ,7H CARBON,7H 304 ST,7H 316 ST,7H ALUM. ,
     1 7H 90/10 ,7H METAL ,7H STEEL ,7HAINLESS,7HAINLESS,7HBRONZE ,
     2 7HCU - NI/
      WCONV(W) = W/2.505
      QCONV(Q1) = Q1/3.968
      TCON(T)=(T-32.17)/1.8
      PCONV(P) = P * 0.03452
      Q=QDUM/1.E6
      WT=WTDUM/1.E6
      WTS = Q/950.0
      WT1 = WCONV(WT)
      WTS1 = WCONV(WTS)
      QC1 = QCONV(Q)
      TC1=TCON(TTIN)
      TC2=TCON(TOUT)
      TC3=TCON(TSAT)
      DP1 = PCONV(DPTOT)
      PSAT1 = PCONV(PSAT)
      PS11 = PCONV(PS1)
      PS21 = PCONV(PS2)
      TLMC = TLM/1.8
      WRITE(6,900)
      WRITE(6,910)WTS,WTS1,TSAT,TC3,PSAT,PSAT1
      IF(KCOND-2)150,100,150
  100 WRITE(6,925)PS1,TS1,UO1,FRAC,TTIN,TR1,TLM1,PS2,TS2,UO2,FRAC2,TIN2,
     1TR2,TLM2
  150 CONTINUE
      WRITE(6,920)WT,WT1,TTIN,TC1,TOUT,TC2,Q,QC1,TLM,TLMC,CLFAC
      WRITE(6,930)VMIN,VMAX,DPMAX,TLMIN,TLMAX,PSMIN,PSMAX
      WRITE(6,940)(SHETM(MN,I),I=1,2),(TUBEM(KMETL,I),I=1,2),BWG
      DO 600 I=1,10
      IF(CITEM(I,1).GT..99E30)GO TO 700
  600 WRITE(6,950)CITEM(I,6),CITEM(I,4),CITEM(I,5),CITEM(I,3),CITEM(I,2)
     1,CITEM(I,12),CITEM(I,10),CITEM(I,7),CITEM(I,9),CITEM(I,11),
     2CITEM(I,1) ,CITEM(I,8)
  700 CONTINUE
  900 FORMAT(36H1** SURFACE CONDENSER DESIGN        ./)
  910 FORMAT(22H0** STEAM CONDITIONS  ./,
     1       22H    TOTAL FLOW LEAVING,3X,F7.3,8H MMLB/HR,8X,F7.3,8H MMK
     2G/HR,/,26H    SATURATION TEMP.       ,F6.2,6H DEG.F,11X,F6.2,6H DEG   53890
     3.C,/,  26H    SATURATION PRESSURE    ,F6.2,6H IN HG,11X,F6.2,7H KG/   53900
     4CM2,/ )                                                               53910
  920 FORMAT(32H0** CIRCULATING WATER CONDITIONS,/,                         53920
     1       15H    FLOW RATE  ,10X,   F7.3, 8H MMLB/HR,8X,F7.3,8H MMKG/    53930
     2HR,/,  26H    TEMP.ENTERING          ,F6.2,6H DEG.F,11X,F6.2,6H DEG   53940
     3.C,/,  26H    TEMP.LEAVING           ,F6.2,6H DEG.F,11X,F6.2,6H DEG   53950
     4.C,///,26H ** OVERALL PERFORMANCE    ,/,                              53960
     5       15H    HEAT DUTY   ,8X,    F9.3,10H MMBTU/HR ,5X,F8.3,10H MM   53970
     6KCAL/HR,/,                                                            53980
     7       26H    MEAN TEMP.DIFF.        ,F6.2,6H DEG.F,11X,F6.2,6H DEG   53990
     8.C,/,  22H    CLEANINESS FACTOR ,21X,F5.3,//)                         54000
  925 FORMAT(26H0** MULTIPRESSURE DESIGN  ,/,                               54010
     1       56H                 SATURATION   OVER.   FRAC.   INLET   TEMP. 54020
     2,/,    62H              PRESS.  TEMP.  COEFF.   DUTY    TEMP.   RANGE 54030
     3  LMTD,/,                                                             54040
     4       10H    ZONE 1,F8.2,F8.1,F8.2,F6.2,2F8.1,F7.1,/,                54050
     5       10H    ZONE 2,F8.2,F8.1,F8.2,F6.2,2F8.1,F7.1,//)               54060
  930 FORMAT(67H0** DESIGN RESTRAINTS                 MINIMUM             M 54070
     1AXIMUM      ,/,                                                       54080
     2       29H    TUBE SIDE VELOCITY FT/SEC,4X,F6.2,17X,F6.2,/,           54090
     3       31H    TUBE SIDE PRESSURE DROP PSI,25X,F6.2,/,                 54100
     4       19H    TUBE LENGTH FT.,14X,F6.2,17X,F6.2,/,                    54110
     5       30H    SATURATION PRESSURE,IN HG ,4X,F5.2,18X,F5.2,//)         54120
  940 FORMAT(25H0** DESIGN   PARAMETERS  ,/,19H    PLATE MATERIAL ,2A7,     54130
     1/,19H     TUBE  MATERIAL ,2A7,/,19H    TUBE     GAUGE ,F14.0,//,      54140
     1       56H  DESIGN  TUBE INFORMATION     NO.OF  NO.OF  TUBE SIDE      54150
     2,      26H  OVERALL     TOTAL     COST,11H  ESTIMATED,/,              54160
     3       56H    NO.   O.D  LENGTH  NUMBER  TUBE   SHELL  PRESS VELOC    54170
     4,      26H. COEFF.      SURFACE  M-$ ,11H  TOTAL     ,/,              54180
     5       56H                                 PASSES SER.   DROP         54190
     6,      26H  SERVICE     AREA         ,14H  WEIGHT(TONS))              54200
  950 FORMAT(F7.0,F7.3,F7.1,F9.0,F7.0,F6.0,F7.3,F6.1,F10.3,F11.1,F7.0,      54210
     1F9.0)                                                                 54220
      RETURN                                                                54230
      END                                                                   54240
      SUBROUTINE OUTSM
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/PRSUM/XPRIC(12,21)
      COMMON/PERFO/AUXMW(20,21),TURMW(20,21),ZLOAD(20,21)
      COMMON/PEN/ATTR(20),DATTR(20),AMBTPT(20),BCAPC,NATTR,CAPCST,CMAIN,
     1MACC,AFCR2,XLVL,FLCST,CAPBS,PLDFT(20),STMCT,CUTMP,SHELP,BHTRT(6)
      COMMON/SCOND/TTDMN,TTDMX,TISUM(21)
      DIMENSION CA(12)
   25 FORMAT(55H1*** THE FOLLOWING ARE THE OPTIMIZED DESIGNS GENERATED ,
     117HBY THE BOX METHOD,/,38H  THEY MAKE UP THE COMPLEX AT THE END ,
     233HOF THE OPTIMIZATION PROCEDURE ***,/)
  200 FORMAT(6X,17HZ Z BUND FAN BARE,9X,16HTUBE INFORMATION,6X,
     118H*  AIRSIDE INFO. *,/,6X,18HB P WDTH  ID SURF.,2X,27(1H-),1X,
     218(1H-))
  220 FORMAT(6X,3HA A,10X,4HAREA,4X,28HNO. LGH TEMPS. VEL.  FLOW    ,
     112HTEMPS. VEL  ,4HFLOW,/,6X,3HY N,26X,6HIN OUT,14X,6HIN OUT,/,1X,
     271(1H-),/)
  240 FORMAT(1X,I2,I4,I2,2F4.0,F9.0,1X,2I3,I4,F5.0,F4.1,F7.2,3I4,
     1F7.2)
  260 FORMAT(////,26H ** SUMMARY ** (CONTINUED),/,20X,
     116HTOWER PARAMETERS,16X,11H* PRES.DROP,/,4X,49(1H-),1X,9(1H-),/,4X
     2,59HDESIGN TTD   MAX  FAN FAN PUMP WRT  AUX RNG/  ITD  AIR TUBE,/,
     36X,57HHEAT       BACK  HP  MW.  MW. MW.  MW.  ITD      SIDE SIDE,/,
     46X,14HDUTY       PRES,/,1X,62(1H-),/)
  280 FORMAT(1X,I2,F7.1,F5.1,1X,F4.1,F5.0,3I4,F6.1,F4.2,F6.1,F4.2,F6.1,
     11X)
 2000 FORMAT(1H1)
 2010 FORMAT(54H    *** COST SUMMARY OF MECH. DRAFT DRY COOLING TOWER ,
     110HSYSTEM ***,/,41H *** THE FOLLOWING SHOWS ANNUAL COSTS IN ,
     227HTHOUSANDS FOR THE OPTIMIZED,/,5X,26HDESIGNS OF THE BOX COMPLEX,
     34H ***,//,5X,11HTUBE   HEAT,24X,15HANNUAL    INCR.,9X,
     37HWATER  ,
     418HELEC. INTRST  MILL,/,4X,35HMODULE REJECT  PIPE   CAPC  ENERGY ,
     411H  FUEL      .    RECVRY  SUB-  DURING   PER   TOTAL,/,5X,
     547HFUEL   COND.
     511HCOST    O+M,
     655H   COST   PEN.   PEN.    COST     COST    COST    TURB.   ,
     726HSTAT. CONSTR    KWH   COST,/,1X,97(1H-))
2030 FORMAT(1X,I2,5F7.1,F10.1,5F7.1,F7.3,F8.1)
     IF (NSUM) 1000,1000,350
 350 KOT=1
     WRITE(NFO,25)
 600 WRITE(NFO,200)
     DUM=0.
     DO 30 J=1,NATTR
  30 DUM=DUM+PLDFT(J)*DATTR(J)
     DUM=DUM*1000.*BCAPC
     WRITE(NFO,220)
     DO 640 K=1,NSUM
     WRITE(NFO,240)K,ISUM(10,K),ISUM(9,K),(SSUM(I,K),I=3,5),
    1(ISUM(I,K),I=12,13),ISUM(4,K),SSUM(12,K),(SSUM(I,K),I=1,2),
    2(ISUM(I,K),I=5,6),ISUM(3,K),SSUM(9,K)
 640 CONTINUE
     WRITE(NFO,260)
     DO 680 K=1,NSUM
     WRITE(NFO,280)K,SSUM(8,K),TISUM(K),SSUM(6,K),SSUM(11,K),ISUM(11,K)
    1,ISUM(2,K),
    2  ISUM(7,K),SSUM(13,K),SSUM(14,K),SSUM(7,K),SSUM(15,K),SSUM(16,K)
 680 CONTINUE
 800 NPAGE=NPAGE+1
C *** OUTPUT   COST OF AIR COOLER -  AREA*COST(1)+HP*COST(2)=TOTAL
 910 WRITE(NFO,2000)
 920 WRITE(NFO,2010)
     DO 930 K=1,NSUM
     CHP=PRICE(2,K)*1.E-3
     CSA=PRICE(1,K)*1.E-3
     DUM1=XPRIC(4,K)*1000./DUM
     DO 925 I=1,12
 925 CA(I)=XPRIC(I,K)*1.E-3
     WRITE(NFO,2030)K,CSA,CHP,(CA(I),I=1,3),CA(12),CA(5),
    1(CA(I),I=7,10),DUM1,CA(4)
 930 CONTINUE
     WRITE(NFO,1100)
     DO 1900 K=1,NATTR
     IF(K.EQ.7)WRITE(NFO,2000)
     WRITE(NFO,1200)ATTR(K),PLDFT(K)
     WRITE(NFO,1300)(ZLOAD(K,I),I=1,NSUM)
     DO 1800 I=1,NSUM
     AUXMW(K,I)=AUXMW(K,I)*1.E-03
     TURMW(K,I)=TURMW(K,I)*1.E-03
1800 CONTINUE
     WRITE(NFO,1400)(AUXMW(K,I),I=1,NSUM)
     WRITE(NFO,1500)(TURMW(K,I),I=1,NSUM)
```

```
1900 CONTINUE
1100 FORMAT(///,52H *** OFF DESIGN PERFORMANCE OF THE OPTIMIZED DESIGNS
    1,19H IN THE BOX COMPLEX,/,37H TURBINE FIRING RATE,MW,AND AUXILLARY
    2,34H MW ARE GIVEN FOR EACH AMBIENT ***,/)
1200 FORMAT(/,7H  TAMB=,F6.1,16H  DEMANDED LOAD=,F6.3)
1300 FORMAT(6H LOAD ,21F6.3)
1400 FORMAT(6H A. MW,21F6.1)
1500 FORMAT(6H T. MW,21F6.0)
1000 NSUM=0
     RETURN
     END
```

```
      SUBROUTINE OWARN
C *** PRINT OUT WARNING AND ERROR MESSAGES
      DIMENSION IWARN(20)
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QOUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
 1000 FORMAT(1H1)
 1001 FORMAT(4H ***,17(4H****))
 1002 FORMAT(20H I  WARNING MESSAGES,/4H I  ,4(4H----),/2H I)
 1003 FORMAT(55H I  MINOR CALCULATION ERRORS / PROGRAM EXECUTION CONTIN,
     1 3HUES/2H I/47H I  NO.  S/R   ERROR DESCRIPTION / ACTION TAKEN ,/
     2 13H I  --- -----,2X,8(4H----),/2H I)
 1004 FORMAT(54H I  MAJOR CALCULATION ERRORS / PROGRAM EXECUTION STOPS,
     1 /2H I/51H I  NO.  S/R   ERROR DESCRIPTION / SUGGESTED ACTION ,/
     2 13H I  --- -----,2X,9(4H----),/2H I)
```

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2001 FORMAT(55H I  TUBE FLUID PASSED THROUGH TRANSITION ZONE / IF OVER,
    1 9HALL CASE./
    2 60H I  RERUN WITH STEPWISE OPTION TO INSURE REASONABLE RESULTS.,
    3 /2H I)
 2009 FORMAT(23H I  SPEC. TUBE COUNT OF,I5,24H / BUNDLE DOES NOT AGREE,
    1 5H WITH,/23H I  CALCULATED VALUE OF,I5,
    2 30H / BUNDLE.  PROGRAM USED SPEC.,/2H I)
 2010 FORMAT(44H I  FAN TO FACE AREA RATIO LESS THAN .35 /   /
    1        44H I  CHECK FAN RING I.D. AND NO. BUNDLES/BAY. / 2H I)
 2011 FORMAT(70H I  FAN DIAMETER EXCEEDS BUNDLE WIDTH(S) OR FAN/FACE ARE
    1A EXCEEDS 0.7./44H I  BAY MAY BE SHARED BY MORE THAN ONE UNIT. /
    2 52H I  AIR DYNAMIC PRESSURE DROP MAY BE OVER PREDICTED./2H I)
 2012 FORMAT(37H I  PCT. UNDERDESIGN IS CONSERVATIVE. / ,
    1 60H I  RECOMMEND RERUN TO FIND OUTLET TEMP (CARD 1 ITEM 1 = 4)  /
    2  2H I)
 2013 FORMAT(41H I  DANGER OF FREEZING OR SOLIDIFICATION./2H 2)
 3002 FORMAT(55H I   2  UOCON  CONV. METHOD FAILED IN COLBURN-HOUGEN/ U,
    1 8HSED WARD ,/2H I)
 3005 FORMAT(55H I   5  QQUAL  CP AND HFG NOT CONSISTENT WITH T-Q CURVE,
    1 15H/ CALCULATES DX ,
    2 /2H I,13X,20HPROPORTIONAL TO DQ.   ,/2H I)
 3006 FORMAT(57H I   6  EXINI  THE VAPOR PRESSURE CURVE HAS BEEN ADJUSTE
    1D     /56H I              TO AGREE WITH ENTERING FLOW CONDITIONS
    2      /56H I              (DEW POINT, PCT. NON-COND., INLET PRESS.)
    3      / 2H I)
 3007 FORMAT(55H I   7  QBALN  CONV. TO CALC, AVG. CP FAILED/ LAST VALU,
    1 6HE USED  ,/2H I)
 3008 FORMAT(55H I   8  QPROF  CONV. METHOD FAILED/ LAST VALUE USED    ,
    1 /2H I,13X,31HCHECK INPUT VAPOR PRESSURE DATA  ,/2H I)
 3011 FORMAT(55H I  11  SUPER  REQUIRED AIR VELOCITY EXCEEDS 3000 FPM/ ,
    1 17HCASE TERMINATED    ,/2H I)
 3013 FORMAT(55H I  13  HTSEN  CONV. FAILED IN CALC. COEF. FOR VERTICAL,
    1 17H TUBES IN LAMINAR  /2H I,13X,5HFLOW. ,/2H I)
 3016 FORMAT(55H I  16  EXINI  SPECIFIED INLET PRESSURE DIFFERS BY MORE,
    1        17H THAN 5 PCT. FROM/
    2        55H I             CALCULATED VALUE OBTAINED FROM CONSIDERI,
    3        17HNG VAPOR PRESSURE/
    4        55H I             AND ENTERING QUALITY / LARGER VALUE USED/
    5         2H I)
 3017 FORMAT(56H I  17  EXINI  CALC. DEW POINT TEMP. EXCEEDS INLET TEMP.
    1       /48H I             / INLET TEMP. RESET TO DEW POINT.,/2H I)
 3018 FORMAT(55H I  18  GEOM1  SPEC. AND CALC. BUNDLE WIDTH DIFFER /
    1       /32H I             CALC. VALUE USED.,/2H I)
 3019 FORMAT(74H I  19  DPAIR  AIRSIDE STATIC DP IS HIGH. IF AXIAL FAN U
    1SED,THE FAN EFFIC./ 2H I,13X,56HUSED MAY BE HIGH. / CHECK FAN PERF
    2OR. AND EFFIC. CURVES.)
 3020 FORMAT(60H I  20  QBALN  GIVEN DUTY AND CALC. TUBE SIDE DUTY DIFFE
    1R BY,/73H I             MORE THAN 50 PCT. /  GIVEN DUTY SET TO ZER
    2O AND CASE CONT. , /2H I)
 3021 FORMAT (54H I  21  CHANL  DP. CONVERGENCE FAILED/RESULTS SHOULD S,
     118HTILL BE REASONABLE. / 2H I)
 3022 FORMAT(37H I  22  HTURB  EXTRAPOLATION OCCURRED./2H I)
 3023 FORMAT(37H I  23  QTURB  EXTRAPOLATION OCCURRED./2H I)
 3050 FORMAT(55H I  50  SUPER  CONV. FOR PERFORMANCE FAILED. MAY BE TOO.
     1 14H EXTREME TEMP.  ./2H I,13X,8HPROFILE.  ./2H I)
 3062 FORMAT(38H I  62  QBALN  TEMPERATURE CROSS FOUND  ./2H I)
 3064 FORMAT(55H I  64  QBALN  HOT AND COLD CALC. DUTY DIFFER BY MORE T,
     1 11HHAN 50 PCT.  ./2H I)
 3065 FORMAT(55H I  65  UOSEN  WALL TEMP. CONV. FAILED REFERENCE VISCOS,
     1 16HITY SPEC. SHOULD /2H I,13X,23HBE CLOSER TO WALL TEMP.  ./2H I)
 3069 FORMAT(46H I  69  PZONE  NTU CONV. FAILED/ REPORT TO PFR,/2H I)
 3070 FORMAT(48H I  70  MTDOV  PROBABLE TEMPERATURE CROSS FOUND.,/2H I)
 3071 FORMAT(49H I  71  MTDOV  CONV. METHOD FAILED/ REPORT TO PFR,/2H I)
 3072 FORMAT(96H I  72  EXINI DESUPERHEAT ZONE DUTY DIFFERS BY 50 PCT.
     1FROM CALC. VALUE/ CHECK CPV AND PROCESS./2H I)
 3073 FORMAT(93H I  73  EXINI  SUBCOOL ZONE DUTY DIFFERS BY 50 PCT. FORM
     1 CALC. VALUE./ CHECK CPL AND PROCESS./2H I)
 3075 FORMAT(46H I  75  EXCON  NTU CONV. FAILED/ REPORT TO PFR,/2H I)
 3097 FORMAT(63H I  97  PPAUT  AUTOMATIC PROPERTY CODE (CARD 6 ITEM 1) S
     1PECIFED/2H I,13X,25HNOT INCLUDED IN DATA BANK/2H I)
 3098 FORMAT(51H I  98  PPROP  TEMP. INPUT LESS THAN  .1 RANKINE OR    ,
     1 /2H I,13X,33HTEMP.  AIR  LESS THAN 200 RANKINE  ,/2H I)
      XAOF=(DBW+4.0)/12.0
      MMC=1
      NWARN=0
      IF (KGO-2) 500,100,500
C *** HEADING
  100 IF (NWARN) 110,110,120
  110 IF (MM   ) 900,900,120
  120 WRITE (NFO,1000)
C *** WARNING MESSAGES
      IF (NWARN) 300,300,200
  200 WRITE (NFO,1001)
      WRITE (NFO,1002)
      DO 299 I=1,NWARN
      IF (IWARN(I)- 1) 299,210,212
  210 WRITE (NFO,2001)
  212 CONTINUE
  226 IF (IWARN(I)- 9) 299,227,228
  227 WRITE (NFO,2009) NTT,NT2
  228 IF (IWARN(I)-10) 299,229,230
  229 WRITE (NFO,2010)
  230 IF (IWARN(I)-11) 299,231,232
  231 WRITE (NFO,2011)
  232 IF (IWARN(I)-12) 299,233,234
  233 WRITE (NFO,2012)
  234 IF (IWARN(I)-13) 299,235,236
  235 WRITE (NFO,2013)
  236 CONTINUE
  299 CONTINUE
```

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C *** MINOR ERROR MESSAGES                                              56660
  300 IF ( MM        ) 400,400,306                                      56670
  306 IF ( KERR(I)-50) 308,309,309                                      56680
  308 WRITE (NFO,1001)                                                  56690
      WRITE (NFO,1003)                                                  56700
  309 DO 399 I=1,MM                                                     56710
  310 NWARN=I-1                                                         56720
      IF (NWARN)         313,313,311                                    56730
  311 DO 312 J=1,NWARN                                                  56740
      IF (KERR(I)-KERR(J)) 312,399,312                                  56750
  312 CONTINUE                                                          56760
      IF ( KERR(I)-50) 313,350,350                                      56770
  313 IF(KERR(I)-2)399,316,317                                          56780
  316 WRITE (NFO,3002)                                                  56790
  317 IF(KERR(I)-5)399,322,323                                          56800
  322 WRITE (NFO,3005)                                                  56810
  323 IF ( KERR(I)- 6) 399,324,325                                      56820
  324 WRITE (NFO,3006)                                                  56830
  325 IF ( KERR(I)- 7) 399,326,327                                      56840
  326 WRITE (NFO,3007)                                                  56850
  327 IF ( KERR(I)- 8) 399,328,331                                      56860
  329 WRITE (NFO,3008)                                                  56870
  331 IF(KERR(I)-11)399,334,335                                         56880
  334 WRITE (NFO,3011)                                                  56890
  335 IF(KERR(I)-13)399,338,343                                         56900
  338 WRITE (NFO,3013)                                                  56910
  343 IF ( KERR(I)-16) 399,344,345                                      56920
  344 WRITE (NFO,3016)                                                  56930
  345 IF ( KERR(I)-17) 399,346,347                                      56940
  346 WRITE (NFO,3017)                                                  56950
  347 IF ( KERR(I)-18) 399,348,349                                      56960
  348 WRITE (NFO,3018)                                                  56970
  349 IF ( KERR(I)-19) 399,6000,6010                                    56980
 6000 WRITE (NFO,3019)                                                  56990
 6010 IF (KERR(I)-20) 399,6020,6021                                     57000
 6020 WRITE(NFO,3020)                                                   57010
 6021 IF (KERR(I)-21) 399,6022,6023                                     57020
 6022 WRITE (NFO,3021)                                                  57030
 6023 IF(KERR(I)-22)399,6024,6025                                       57040
 6024 WRITE(NFO,3022)                                                   57050
 6025 IF(KERR(I)-23)399,6026,6027                                       57060
 6026 WRITE(NFO,3023)                                                   57070
 6027 CONTINUE                                                          57080
      IF ( KERR(I)-50) 399,350,350                                      57090
C *** MAJOR ERROR MESSAGES                                              57100
  350 IF (MMC        ) 354,354,352                                      57110
  352 WRITE (NFO,1001)                                                  57120
      WRITE (NFO,1004)                                                  57130
      MMC=-1                                                            57140
  354 IF ( KERR(I)-50) 399,355,356                                      57150
  355 WRITE (NFO,3050)                                                  57160
  356 IF(KERR(I)-62)360,359,360                                         57170
  359 WRITE (NFO,3062)                                                  57180
  360 IF ( KERR(I)-64) 362,361,362                                      57190
  361 WRITE (NFO,3064)                                                  57200
  362 IF ( KERR(I)-65) 364,363,364                                      57210
  363 WRITE (NFO,3065)                                                  57220
  364 IF ( KERR(I)-69) 366,365,366                                      57230
  365 WRITE (NFO,3069)                                                  57240
  366 IF ( KERR(I)-70) 368,367,368                                      57250
  367 WRITE (NFO,3070)                                                  57260
  368 IF ( KERR(I)-71) 370,369,370                                      57270
  369 WRITE (NFO,3071)                                                  57280
  370 IF ( KERR(I)-75) 372,371,372                                      57290
  371 WRITE (NFO,3075)                                                  57300
  372 IF(KERR(I)-97)380,379,380                                         57310
  379 WRITE (NFO,3097)                                                  57320
  380 IF (KERR(I)-98) 382,381,382                                       57330
  381 WRITE (NFO,3098)                                                  57340
  382 IF (KERR(I)-72) 384,383,384                                       57350
  383 WRITE(NFO,3072)                                                   57360
  384 IF (KERR(I)-73) 386,385,386                                       57370
  385 WRITE(NFO,3073)                                                   57380
  386 CONTINUE                                                          57390
  399 CONTINUE                                                          57400
  400 WRITE (NFO,1001)                                                  57410
      GO TO 900                                                         57420
C *** WARNING MESSAGES ARE SET HERE                                      57430
  500 CONTINUE                                                          57440
C *** TRANSITION ZONE CHECK FOR SENSIBLE CASES                          57450
  502 IF (RE12(1,1)-2000.) 520,520,503                                  57460
  503 IF (RE12(2,1)-1.0E4) 504,520,520                                  57470
  504 NWARN=NWARN+1                                                     57480
      IWARN(NWARN)=1                                                    57490
  520 CONTINUE                                                          57500
C *** TUBE COUNT DISCREPANCY                                             57510
  570 IF (NTT-NT2-NTR) 572,572,574                                      57520
  572 IF (NT2-NTT-NTR) 580,580,574                                      57530
  574 NWARN=NWARN+1                                                     57540
      IWARN(NWARN)=9                                                    57550
C *** SMALL FAN/FACE AREA RATIO                                         57560
  580 IF (RFNPL-.35)    582,582,590                                     57570
  582 NWARN=NWARN+1                                                     57580
      IWARN(NWARN)=10                                                   57590
C *** FAN DIA. EXCEED BUND. WIDTH.                                      57600
  590 IF (ZBUP*ZBYP-1.1)    592,600,600                                 57610
  592 IF (DFAN-XAOF*ZBUP)   594,596,596                                 57620
  594 IF (RFNPL-.7)         600,596,596                                 57630
  596 NWARN=NWARN+1                                                     57640
      IWARN(NWARN)=11                                                   57650
  600 CONTINUE
  602 IF (KCI - 1  )    610,604,610
  604 IF (XREX+10.0)    606,610,610
  606 NWARN=NWARN+1
      IWARN(NWARN)=12
C *** FREEZING/SOLIDIFICATION
  610 IF (TWALL-TTMIN-5.) 615,620,620
  615 NWARN=NWARN+1
      IWARN(NWARN)=13
  620 CONTINUE
      GO TO 100
  900 RETURN
      END
```

```
      SUBROUTINE PIPDIV(D,L,XMT,TLMAX,FJ,SJ,I)
C *** GIVEN
C ***       D     - PIPE DIAMETER IN INCHES
C ***       L     - LENGTH OF PIPE IN FEET
C ***       XMT   - NUMBER OF PIECES
C ***       TLMAX - MAXIMUM SHIPPABLE LENGTH IN FEET
C ***       FJ    - FIELD LABOR RATE IN DOLLARS/HR
C ***       SJ    - COST OF SHOP JOINT IN DOLLARS/DIAMETER INCH
C ***       I     - SUBSCRIPT OF ARRAY
C *** THIS ROUTINE ADDS A FIELD JOINT EVERY TLMAX FEET TO FIELD(I)
C ***              ADDS A SHOP JOINT EVERY 48 OR 12 FT. TO XSHOP(I)
C ***              ADDS AN EXPANSION JOINT EVERY 110 FEET TO EXJOT(I)
      COMMON/BCK/XMCST(20).PIPDM(20),XSHOP(20).FIELD(20).EXJOT(20)
      DIMENSION EJARR(20).DIARR(20)
C *** ARRAY OF PIPE SIZES (INCHES)
      DATA DIARR/4.026.8.071,12.09,17.25,23.25,29.25,35.25,42.,48.,54.,
     1           60., 66., 72., 78., 84., 90., 96., 108., 114., 144./
C *** ARRAY OF COSTS FOR EXPANSION JOINTS (1976 PRICES)
      DATA EJARR/ 134.00, 234.00, 321.00, 508.00, 850.00,
     1            922.00, 1150.0, 2200.0, 3250.0, 3850.0,
     2            4500.0, 5300.0, 6100.0, 7500.0, 9300.0,
     3            11100., 13000., 16800., 18000., 28000./
      IF(D-48.01)10,20,20
   10 F=TLMAX
      S=AMIN1(TLMAX,48.)
      GO TO 40
   20 IF(D-96.01)30,35,35
   30 F=AMIN1(TLMAX,48.)
```

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      S=AMIN1(TLMAX,12.)                                                58070
      GO TO 40                                                          58080
   35 F=AMIN1(TLMAX,24.)                                                58090
      S=AMIN1(TLMAX,12.)                                                58100
   40 XNO=AINT(L/F-.01)                                                 58110
      FIELD(I)=FIELD(I)+FJ*(XNO+1.)*XMT*(1.4+1.6*D)                     58120
      XNO=XNO*AINT(F/S-.01)+AINT((L-XNO*F)/S-.01)                       58130
      XSHOP(I)=XSHOP(I)+SJ*XNO*XMT*D                                    58140
      XNO=AINT(L/110.-.01)                                              58150
      EXJOT(I)=XNO*XMT*GRS(DIARR,1,EJARR,1,D,20,JDUM)+EXJOT(I)          58160
      RETURN                                                            58170
      END                                                               58180
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      SUBROUTINE PLENUM(NFAN,DFAN,DL,DHEDW.TSPLM.DENCS.CPLM1,CPLL1,CTPLM 58190
     1,PLMTL,PLLAB,ZBUP)                                                58200
      COMMON/PIPE/XDIA(20).XLGT(20),NN1,NN2,XTOWR,PLNMH,TTTBH,VX,VN,VAVE 58210
C                                                                       58220
C *** THIS SUBROUTINE COMPUTES THE INSTALLED COST FON PLENUM            58230
C                                                                       58240
C                                                                       58250
C *** INPUT VARIABLES ***                                               58260
C     DFAN  = FAN DIAMETER (FT)                                         58270
C     DL    = BUNDLE LENGTH (FT)                                        58280
C     DHEDW = BUNDLE WIDTH (INCH)                                       58290
C     TSPLM = THICKNESS OF PLENUM (INCH)                                58300
C     DEN   = DENSITY OF PLENUM METAL (LB/INCH3)                        58310
C     CPLM1 = UNIT COST FOR PLENUM METAL ($/LB)                         58320
C     FPLM  = INSTALLED COST INDEX (BASED ON MATERIAL COST)             58330
C     NFAN  = NUMBER OF FANS PER BAY                                    58340
C     ZBUP  = NUMBER OF BUNDLES IN PARALLEL PER BAY                     58350
C                                                                       58360
C *** OUTPUT VARIABLE ***                                               58370
C     CTPLM = INSTALLED COST FOR PLENUM ($)                             58380
      ZFAN=NFAN                                                         58390
C                                                                       58400
C *** BASE PLENUM HEIGHT ON 45 DEGREE DISPERSION ANGLE                  58410
      PLNMH=AMAX1((DHEDW/12.*ZBUP-DFAN)/2.,(DL/ZFAN-DFAN)/2.)           58420
      DHPLM=PLNMH                                                       58430
C                                                                       58440
C     SIDE PLENUM AREA (FT2)                                            58450
      SIDEA=2.0*(DL+DHEDW*ZBUP/12.)*DHPLM                               58460
C                                                                       58470
```

```
C     TOP PLENUM AREA (FT2)
      TOPA=DL*DHEDW*ZBUP/12.-ZFAN*3.1416*(DFAN/2.)**2
C
C     PLENUM WEIGHT (LB)
      WTPLM=DENCS*TSPLM*(SIDEA+TOPA)*144.
C
C     PLENUM MATERIAL COST ($)
      PLMTL=CPLM1*WTPLM
C
C     PLENUM INSTALLED LABOR COST
      PLLAB=CPLL1*WTPLM
C
C     PLENUM INSTALLED COST
      CTPLM=PLMTL+PLLAB
C
C
      RETURN
      END


      FUNCTION PNLIM(AMIN,AMAX,AFUNC)
C *** FUNCTION LIMITS AFUNC BETWEEN AMIN AND AMAX
      PNLIM=AFUNC
      IF (AFUNC-AMIN) 10,10,20
   10 PNLIM=AMIN
      GO TO 50
C *** IF AMAX IS LESS THAN AMIN JUST SET PNLIM TO AFUNC
   20 IF (AMAX-AMIN) 50,50,30
   30 IF (AFUNC-AMAX) 50,50,40
   40 PNLIM=AMAX
   50 RETURN
      END
      SUBROUTINE PPAUT
C *** FILL IN AUTOMATIC PHYSICAL PROPERTY CONSTANTS
      DIMENSION AP(16),AP001(16)
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RADI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
C *** WATER (STEAM) CONSTANTS FOLLOW*ODL,ML,KL,CL,MV,KV,CV,HF,SI,VP,PC,T
      DATA AP001/ 53.34,4.40127E-02,-5.1085E-05,0.0,  -2.953,-470.81,
     1 1.074932E6,0.0,   -.17134,1.527E-3,-1.021E-6,0.0,  1.191,-7.0E-4,
     2 6.341E-7,0.0/
      DO 100 K=1,16
  100 AP(K)=AP001(K)
      DO 400 K=1,4
      ODL(K)     =AP(K)
      OML(K)     =AP(K+4)
      OKL(K)     =AP(K+8)
      OCL(K)     =AP(K+12)
  400 CONTINUE
  500 RETURN
      END
```

```
      SUBROUTINE PPAUT1(TF,CPL,DENL,TKL,VISL,KODE)
C *** THIS SUBROUTINE CALCULATES WATER -STEAM PHYSICAL PROPERTIES
C     T = TEMPERATURE DEG.R
C     CPL = HEAT CAPACITY OF WATER IN BTU/LB/F
C     DENL = DENSITY OF WATER IN LB/FT3
C     VISL = VISCOSITY OF WATER IN CENTIPOISES
```

```
      KODE = 0
      T = TF + 460.0
      T2 = T*T
      CPL = 1.191328 - 7.002932E-4*T + 6.3408E-7*T2
      DENL = 53.34 + 4.40127E-2*T -5.1085E-5*T2
      VISL = EXP(-2.953 -470.81/T + 1074932./(T2))
C     ALL THE ABOVE PROPERTIES ARE VALID FOR TEMPERATURES FROM 460 TO
C     1030 DEG.R
      RETURN
      END
```

```
      SUBROUTINE PPCON
C *** ESTABLISH PHYSICAL PROPERTY CONSTANT DETERM. FROM INPUT DATA
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DIO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DFNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),PPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
C *** SET AUTOMATIC DATA HERE
   10 CALL PPAUT
  300 CONTINUE
 1000 RETURN
      END
      SUBROUTINE PPDEN (T,PZ,ZV,AVMW,DENL,DENV,KCLG,ODL)
C *** CALC. VAPOR AND LIQUID DENSITY ,LB/FT3
      DIMENSION ODL(4)
   10 DENL=ODL(1)+ODL(2)*T+ODL(3)*T*T
  200 RETURN
      END
```

```
      SUBROUTINE PPROP (TZ,PZ,KCLG,DENA,VISA,CPA,TKA,PV,KODE,J)
C *** CALC. PHYSICAL PROPERTIES
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      IF (TZ-.1) 10,10,20
   10 KER=98
      GO TO 500
C *** CHECK PREVENTS EXTRAPOLATION OF PROPERTIES PAST THE REF. VALUES
   20 CONTINUE
 1020 T=TZ
   21 IF(J-1)70,70,24
C *** AIR PROPERTIES CHECKED FROM -100F TO 400F (APPLY TO DRY AIR,LOW P)
   24 T=PNLIM(200.,900.,TZ)
   40 X=T-459.7
      DENA=PZ*28.97/(T*10.73)*FALT
      VISA=0.00905+1.191E-4*(X+200.)**0.775
      CPA=0.2401457+2.48709E-7*X+2.990712E-8*X*X
      TKA=6.915297E-3+7.384478E-5*(X+200.)**.8376137
      GO TO 240
   70 CONTINUE
      CALL PPDEN(T,PZ,.1,.1,DENA,DD,KCLG,ODL)
      CALL PPVIS(T,KCLG,VISA,VV,OMV,OML)
      T2=T*T
      CPA=OCL(1)+OCL(2)*T+OCL(3)*T2
      TKA=OKL(1)+OKL(2)*T+OKL(3)*T2
      PRAN(J)=2.42*CPA*VISA/TKA
      GO TO 400
  240 PRAN(J)=2.42*CPA*VISA/TKA
  400 CONTINUE
  500 RETURN
      END
```

```
      SUBROUTINE PPVIS (T,KCLG,VISL,VISV,OMV,OML)
C *** CALC. VAPOR AND LIQUID VISCOSITY, CENTI-POISE
      DIMENSION OMV(4),OML(4)
   10 VISL=EXP(OML(1)+OML(2)/T+OML(3)/T**2)
  200 RETURN
      END
```

```
      FUNCTION PSL(T)
C *** GIVEN T IN DEGREES F TO FIND PRESSURE IN INCHES-HG
      DATA A,B,C,D/3.2437814,5.86826E-03,1.1702379E-08,2.1878462E-03/
      TC=(T-32.)/1.8+273.16
      X=647.27-TC
      RATIO=X/TC*(A+B*X+C*X**3)/(1.+D*X)*2.3026
      P=3206.2/EXP(RATIO)
      PSL=2.036*P
      RETURN
      END
      SUBROUTINE QBALN
C *** CALC. OF HEAT DUTY FROM GIVEN INFORMATION
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,HSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      LAIC=0
    6 TT(2)=TOUT(1)
      IF (KCI-2) 30,36.30
C *** CALC. THE AIR SIDE FLOW RATE
   30 IF (WD(2)-0.001) 36,36,40
   36 W(2)=VAPP*4.500*APPR*ZMP
   40 DO 80 J=1,2
      IF (TOUT(J)-0.1) 42,42,46
   42 TOUT(J)=TIN(J)
   46 TAV(J)=0.5*(TIN(J)+TOUT(J))
   70 CALL PPROP(TAV(J),14.70,J,DEN(J),VIS(J),CP(J),TK(J),PV,0,J)
   80 CONTINUE
      IF (KER) 200,200,1000
C *** FIND DUTY FROM TOUT, KODE=0
C *** CALC. THE PROPERIES FOR EACH ZONE GIVEN IN INPUT ONLY ONCE
  200 CONTINUE
      L=1
  210 T=.5*(TT(1)+TT(2))
      CALL PPROP(T,1.,1,DENLZ(1),VISLZ(1),CPD,TKD,PV,0,1)
      IF (KER) 1212,1212,1000
 1212 CONTINUE
  230 DO 260 J=L,2
  250 Q(J)=W(J)*CP(J)*ABS(TIN(J)-TOUT(J))
  260 CONTINUE
  270 IF (QD(1)-1.0E-6) 280,280,272
  272 CONTINUE
  274 QDUT=QD(1)
C *** CHECK IF GIVEN DUTY AGREES WITH T/S DUTY TO WITHIN 50 PCT.
  278 IF (ABS(Q(1)/QDUT-1.0)-.5) 290,290,279
C *** RESET GIVEN DUTY TO ZERO   AND SET MINOR ERROR 20
```

```
 279 QD(1)=0.0
     KER=20
     CALL ERORF(KER,KERR,KGO,MM)
 280 CONTINUE
 290 CONTINUE
 320 K=1
     J=2
 400 IF (QD(1)-1.E-6) 410,410,440
 410 CONTINUE
 430 QDUT=W(K)*CP(K)*ABS(TIN(K)-TOUT(K))
 440 Q(1)=QDUT
     Q(2)=QDUT
 446 CONTINUE
 472 T=TAV(J)
     LAIC=LAIC+1
 480 TOUT(J)=TIN(J)+QDUT/(W(J)*CP(J))
 492 TAV(J)=0.5*(TIN(J)+TOUT(J))
     IF (ABS(T/TAV(J)-1.0)-0.001) 500,500,494
 494 CALL PPROP(TAV(J),14.70,J,DEN(J),VIS(J),CP(J),TK(J),PV,0,J)
     IF (KER) 495,495,1000
 495 PRALZ(1)=PRAN(1)
     IF (LAIC-20) 472,472,497
 497 KER=7
 498 CALL ERORF (KER,KERR,KGO,MM)
 500 CONTINUE
C *** CHECK FOR IMPOSSIBLE TEMPERATURE OVERLAPS
 510 IF (TOUT(1)-TIN(1)) 520,520,570
 520 IF (TIN(2)-TOUT(2)) 530,530,570
 530 CONTINUE
C *** COCURRENT TEMP. CONSISTENCY CHECKS
 538 IF (TIN(2)-TOUT(1)) 540,570,570
 540 IF(TOUT(2)-TIN(1))580,570,570
C *** COMPARE DUTY VALUES CALC.
 570 KER=62
     GO TO 1000
C *** SET UP THE INLET,OUTLET,AVG.PROPERTIES
 580 DO 700 J=1,2
     DO 700 I=1,2
     T=TIN(J)
     IF (I-2) 594,590,594
 590 T=TOUT(J)
 594 CALL PPROP(T,14.70,J,DEN12(I,J),VIS12(I,J),CPD,TKD,PV,1,J)
     IF (KER) 600,600,1000
 600 CONTINUE
 700 CONTINUE
C *** CALC. INLET NOZZLE PRESSURE DROP
     WB(1)=W(1)/ZIMP
     CALL NOZCT(DNZI,DNZ,WB(1)/ZNOZ(1),VNZ,DEN12,0.0  ,DPNZ,DBW,0.0,1)
C *** NTU BASED ON AIR SIDE
     P=(TOUT(2)-TIN(2))/TD
```

```
      R=(TIN(1)-TOUT(1))/(TOUT(2)-TIN(2))
      TT(2)=TOUT(1)
C *** COMPARE APPR. VELOCITY WITH SPEC. VALUE
  870 IF (KCI-2) 880,930,880
  880 VT=W(2)/(4.5*APPR*ZMP)
      IF (VAPPI-0.01) 920,920,890
  890 VR=(VT/VAPP-1.0)*100.0
      IF (ABS(VR)- 5.0) 930,900,900
  900 WRITE (NFO,2010) VR
      IF (ABS(VR)-150.0) 920,904,904
  904 KER=64
      GO TO 930
  920 VAPP=VT
  930 CONTINUE
 1000 RETURN
 2010 FORMAT (/51H WARNING *** AIR APPROACH VELOCITY CALC. DIFFERS BY,
     1 F8.0,16H PCT. FROM SPEC.)
      END
```

```
      SUBROUTINE QTURB(Q,SAT,XLOAD,NCODE)
C
C     IF NCODE=1 FIND SAT GIVEN Q AND XLOAD
C     IF NCODE=2 FIND Q GIVEN SAT AND XLOAD
C     XLOAD - TURBINE LOAD FACTOR
C     SAT   - SATURATION TEMPERATURE IN DEGREES F OF TURBINE EXHAUST
C     Q     - HEAT REJECT OF THE STEAM TURBINE
      COMMON IDUM,KGO,IDUM1(4),D1(3),IDUM2,KER,KERR(20),ID1(4),MM,ID2(7)
     1,D2(1218)
      COMMON/STIN/XLDFT(6),BP(28),HTRTD(28,6),HTRJD(28,6),NLODS,NBKPR
     1,PLOAD,BPMNM(6),TPMNM(6)
      COMMON/BCKPR/BCKMN,BCKMX
      DIMENSION X(4),N(7),Y(4),Z(28)
      IF(NCODE-1)90,90,80
   80 BBPP=PSL(SAT)
C *** MAKE SURE BBPP IS WITHIN BACK PRESSURE RANGE
      IF(BBPP.LT.BCKMN)BBPP=BCKMN+.00001
      IF(BBPP.GT.BCKMX)BBPP=BCKMX-.00001
   90 CONTINUE
    3 DO 5 I=1,7
    5 N(I)=0
      NP=3
C *** SEE IF XLOAD LIES WITHIN THE RANGE OF XLDFT
```

```
      IF((XLOAD+.001) .LT.XLDFT(NLODS).AND.(XLOAD+.001) .LT.XLDFT(1))
     1N(1)=-1
      IF(XLOAD.GT.(XLDFT(1)+.001) .AND.XLOAD.GT.(XLDFT(NLODS)+.001) )
     1N(1)=1
      IF(XLDFT(1).GT.XLDFT(NLODS))N(1)=(-1)*N(1)
      IF(N(1).NE.0)GO TO 11
C *** FIND XLOAD BETWEEN I AND I-1 POINTS
      DO 10 I=2,NLODS
      IZ=I
      IF(ABS(XLOAD-XLDFT(I-1)).LT..002)GO TO 4
      IF(XLOAD-XLDFT(I-1))1,4,2
    1 IF(XLOAD-XLDFT(I))10,70,20
    2 IF(XLOAD-XLDFT(I))20,70,10
    4 IZ=I-1
      GO TO 70
   10 CONTINUE
C *** IF XLOAD IS OUTSIDE RANGE OF XLDFT USE LAST 3 OR FIRST 3 POINTS
C *** DEPENDING ON WHETHER OR NOT XLDFT IS DECREASING OR INCREASING
   11 I=NLODS
      IF(N(1).EQ.(-1))I=1
   20 IF(I.GT.2)GO TO 30
C *** IF XLOAD IS  ON LOW END USE FIRST 3 POINTS.  IF IT IS ON HIGH END
C *** USE LAST 3 POINTS.  OTHERWISE USE 4 POINTS - 2 ON EITHER SIDE
C *** OF XLOAD
      N1=1
      N2=2
      N3=3
      GO TO 50
   30 IF(I.EQ.NLODS)GO TO 40
      NP=4
      N4=I+1
   40 N1=I-2
      N2=I-1
      N3=I
C *** STORE LOADS IN Y ARRAY
   50 Y(1)=XLDFT(N1)
      Y(2)=XLDFT(N2)
      Y(3)=XLDFT(N3)
      IF(NP.EQ.4)Y(4)=XLDFT(N4)
      GO TO (100,200),NCODE
C *** FOR NCODE=1 FIND THE HEAT REJECT CORRESPONDING TO XLOAD
C *** FOR EACH BACK PRESSURE AND STORE IN Z ARRAY
  100 DO 125 K=1,NBKPR
      Z(K)=GRS(Y,1,HTRJD(K,N1),28,XLOAD,NP,N(2))
  125 CONTINUE
      BBPP=GRS(Z,1,BP,1,Q,NBKPR,N(3))
  150 SAT=TSL(BBPP)
      GO TO 300
C *** FOR NCODE=2  FIND THE HEAT REJECT CORRESPONDING TO SAT FOR EACH
C *** LOAD AND STORE IN X ARRAY
```

```
  200 CONTINUE
      X(1)=GRS(BP,1,HTRJD(1,N1),1,BBPP,NBKPR,N(2))
      X(2)=GRS(BP,1,HTRJD(1,N2),1,BBPP,NBKPR,N(3))
      X(3)=GRS(BP,1,HTRJD(1,N3),1,BBPP,NBKPR,N(4))
      IF(NP.EQ.4)X(4)=GRS(BP,1,HTRJD(1,N4),1,BBPP,NBKPR,N(5))
C *** FIND Q CORRESPONDING TO XLOAD
      Q=GRS(Y,1,X,1,XLOAD,NP,N(6))
      GO TO 300
   70 I=IZ
      GO TO (225,250),NCODE
  225 BBPP=GRS(HTRJD(1,I),1,BP,1,Q,NBKPR,N(7))
      GO TO 150
  250 CONTINUE
      Q=GRS(BP,1,HTRJD(1,I),1,BBPP,NBKPR,N(7))
C *** SET MINOR ERROR IF EXTRAPOLATION OCCURRED
  300 DO 400 I=1,7
      IF(N(I))450,400,450
  400 CONTINUE
      GO TO 500
  450 KER=23
      CALL ERORF(KER,KERR,KGO,MM)
  500 RETURN
      END
```

```
      FUNCTION RNUM(DUMMY)
C *** THIS FUNCTION USES THE LEHMER MULTIPLICATION CONGINENTIAL METHOD
C *** OF GENERATING PSUEDO RANDOM NUMBERS. IT IS BASED ON A MODULUS
C *** OF 60 BITS/WORD FOR THE CDC6000 SERIES COMPUTER.
      COMMON/RAND/SEED,XMODU,XNUM
   10 WIX=XNUM*SEED
      XNUM=AMOD(WIX,XMODU)
      RNUM=XNUM/XMODU
      RETURN
      END
      SUBROUTINE SCDES(VMIN,VMAX,TLMIN,TLMA,TOUT,TTIN,WT,KMETL,KGAGE,
     1MN,GC,PI,KCOND,CLFAC,DPMAX,CPLI,TSAT,PSMAX,PSMIN,DPTOT,DAY,CITEM,
     2KNTR1,CPEFF,CMAIN,AFCR2,CAPCST,AFCR1)
      COMMON IDUM,KGO,IDUM1(4),D1(3),IDUM2,KER,KERR(20),ID1(4),MM,ID2(7)
     1,D2(1218)
      DIMENSION CNEW(15),CITEM(10,15)
      DIMENSION DTOA(5),DTTHA(7),BWGA(7)
C *** THIS S/R IS A DESIGN S/R FOR STEAM SURFACE CONDENSER
      DATA DTOA/0.75,0.875,1.0,1.125,1.25/
      DATA DTTHA/.022,.028,.035,.049,.065,.083,.109/
      DATA BWGA/24.,22.,20.,18.,16.,14.,12./
      TLMAX=80.
C     DEFINE INITIAL TEMP. DIFF.
      TITD = TSAT - TTIN
C     DEFINE TERMINAL TEMP. DIFF.
      TTD = TSAT - TOUT
C     DEFINE TEMP. RISE
      TR = TOUT - TTIN
      TLM = TR/ALOG(TITD/TTD)
C     CALCULATE HEAT DUTY
C *** CALCULATE WATER PROPERTIES AT AVG. TEMP.
      TTAV = 0.5*(TTIN + TOUT)
      X=TTAV+460.
      CP=1.191328-7.002932E-4*X+6.3408E-7*X*X
      Q = WT * CP * TR
      CALL PPAUT1(TTIN,CP,DEN,TKL,VIS,KODE)
      DO 10 I=1,10
   10 CITEM(I,1) = 1.E30
      M= 0
C *** IF DPMAX,VMAX,VMIN,TLMAX,AND TLMIN NOT GIVEN,SET TO HIGH DEFAULT
C *** VALUE
      IF(DPMAX.LT.01) DPMAX = 20.0
      IF(VMIN.LT.01) VMIN = 3.0
      IF(VMAX.LT.01) VMAX = 12.0
      IF(TLMIN.LT.01) TLMIN = 20.0
      IF(TLMAX.LT.01) TLMAX = 80.0
      KOUNT=0
C     WRITE(6,800)
C *** ONLY ALLOW 1 SHELL IN SERIES TO SAVE TIME
C *** DO 700 NSER=1,2
      NSER=1
      ZNS = NSER
C     LOOP FOR NO. OF PASSES
C *** ONLY ALLOW 1 TUBE PASS TO SAVE TIME
C *** DO 600 NP=1,2
      NP=1
      IF(KCOND - 2)90,70,90
   70 IF(NP-2)90,80,90
   80 IF(NSER-1)90,600,90
   90 CONTINUE
```

```
      ZNP = NP
C *** ONLY DO 3 MIDDLE TUBE DIAMETERS TO SAVE TIME
C *** DO 500 I=1,5
      DO 500 I=2,4
C *** SET STARTING VELOCITY TO MAXIMUM-VSTART = VMAX
C *** VT - TUBE SIDE VELOCITY BASED ON INLET CONDITIONS
      VT = VMAX
      DTO = DTOA(I)
      DTTH = DTTHA(KGAGE)
      BWG = BWGA(KGAGE)
      DTI = DTO - 2. * DTTH
      KCOUN = 0
      DELV = 0.5
      KER=0
      DPTOT = 0.0
      COST = 0.0
      SCCT = 0.0
      CST = 0.0
C *** AX = AREA BASED ON THE INSIDE DIA. OF TUBE
      AX =.7854 *(DTI/12.0)**2
C *** CA LCULATE NO. OF TUBES
  100 CONTINUE
C *** IDN = DESIGN NUMBER
      KOUNT = KOUNT + 1
      IDN = KOUNT
C *** NT - NO.OF TUBES PER SHELL BASED ON INLET VELOCITY,VT
      NT = WT/((VT*3600./ZNP)*AX*DEN)
      ZNT = NT
C *** CALCULATE CROSS-SECTIONAL AREA
      AXT = AX * ZNT/ZNP
      GT = WT/AXT
C *** CALCULATE TUBE SIDE REYNOLDS NO.
      RE = GT * DTI/(29.0*VIS)
C     CALCULATE SURFACE AREA PER UNIT LENGTH
      ASL = ZNT * PI * DTO/12.0 * ZNS
C *** CALL UCOND TO CALCULATE OVERALL COEFFICIENT
      CALL UCOND(VT,UCLN,DTO,TTIN,KMETL,KGAGE,UBASE,FTEMP,FMETL)
      UO = CLFAC * UCLN
      IF(KCOND-1)120,120,130
C     CALCULATE AREA REQUIRED
C *** SINGLE PRESSURE CONDENSER
  120 AREQ = Q/(UO * TLM)
      GO TO 150
C *** MULTIPRESSURE CONDENSER
  130 CALL SCDSMP(TSAT,TTIN,TOUT,VT,Q,   WT,DTO,KMETL,KGAGE,
     1CLFAC,TS1,TS2,PS1,PS2,AZ1,AZ2,Q1,Q2,AREQ,FRAC,PSMAX,PSMIN,
     2TLM,TLM1,TLM2,TR1,TR2,UO1,UO2,TIN2,FRAC2)
C     WRITE(6,900)
  150 KCOUN = KCOUN + 1
      IF(KCOUN-20)200,300,300
  200 CONTINUE
C     CALCULATE  TUBE LENGTH REQUIRED
      TLREQ = AREQ/ASL
C     MAKE TLREQ A ROUND FIGURE - UPWARD
      K = TLREQ + 0.5
      TL = K
C *** CHECK TO SEE IF TUBE LENGTH IS LESS THAN MIN. LENGTH REQUIRED
      IF(TL-TLMIN)210,225,225
C *** IF LESS,SET ERROR CODE AND EXIT
C     SET ERROR CODE
  210 KER=2
      GO TO 400
C     CHECK TO SEE IF TUBE LENGTH GREATER THAN TLMAX
  225 IF(TL-TLMAX)250,250,230
C     IF GREATER, REDUCE TUBE SIDE VELOCITY BY 0.5
  230 VT = VT - DELV
C     CHECK TO SEE IF TUBE SIDE VELOCITY IS LESS THAN VMIN
      IF(VT-VMIN)235,100,100
C     IF LESS ,EXIT OTHERWISE CONTINUE
C     SET ERROR CODE
  235 KER=3
      GO TO 400
  250 CONTINUE
C     CALCULATE TOTAL SURFACE AREA
      ASTOT = TL * ASL
      DL = 12.0 * TL
C     CALCULATE TOTAL PRESSURE DROP
      CALL DPSEN(DTI,DL,0,GT,RE,0.,DEN,DUM1,DP,DUM2)
      DPTOT = (2.0*DEN *VT**2/(2.0*GC)/144.0   +DP)*ZNP
      DPTOT = DPTOT * ZNS
C *** CALCULATE CONDENSER COST BY CALLING SCSBP
      CALL SCSBP(DTO,DTI,KMETL,MN,TL,SCCT,CST,COST,NT,PR,KCOND,WTOTL,
     1KER,ZNS,CSTPB,CPLI)
C *** TOTAL COST OF CONDENSER AND TUBES
      GO TO 400
  300 CONTINUE
C     SET ERROR CODE
      KER=1
  400 CONTINUE
C     WRITE(6,1000)NP,NT,DTO,TL,TLREQ,VT,UCLN,UD,DPTOT,COST,ASTOT,KCOUN,
C    1KERR,NSER,SCCT,CST,IDN
C     M = M + 1
      IF(M-50)410,405,405
  405 WRITE(6,800)
      M = 0
  410 CONTINUE
      IF(VT.LT.VMIN) GO TO 419
      IF(VT.GT.VMAX) GO TO 419
      IF(DPTOT.GT.DPMAX) GO TO 419
      IF(KER)415,415,500
  415 CONTINUE
      CNEW(14)=COST
C *** DETERMINE KW FOR PUMP POWER FOR CONDENSER
      XKW=WT*DPTOT/CPEFF/1151142.
C *** FIND CAPITAL,CAPACITY, AND OPERATING COST. CMAIN IS THE
C *** AVERAGE WEIGHTED COST OF POWER PER KW PER YEAR
      COST=1000.*COST*AFCR1+XKW*CAPCST*AFCR2+XKW*CMAIN/1000.
      COST=COST/1000.
      CNEW(1) = COST
      CNEW(2) = NP
      CNEW(3) = NT
      CNEW(4) = DTO
      CNEW(5) = TL
      CNEW(6) = IDN
      CNEW(7) = VT
      CNEW(8) = WTOTL/2000.0
      CNEW(9) = UO
      CNEW(10) = DPTOT
      CNEW(11) = ASTOT
      CNEW(12) = NSER
      CNEW(13)=GT
      CNEW(15)=FRAC
      CALL STORE(3,15,CITEM,CNEW)
  419 CONTINUE
C *** CHECK IF TOTAL PRESSURE DROP GREATER THAN MAX. PRESSURE DROP
      IF(DPTOT-DPMAX)420,420,430
C *** IF PRESSURE DROP GREATER,REDUCE THE VELOCITY
C *** OTHERWISE CHECK TO SEE IF VELOCITY LESS THAN VMIN
  420 IF(VT-VMIN)500,500,430
C *** IF LESS THAN OR EQUAL,CONTINUE OTHERWISE REDUCE THE VELOCITY
  430 VT = VT - DELV
C     GO BACK AND RECALCULATE NT
      GO TO 100
  500 CONTINUE
  600 CONTINUE
  700 CONTINUE
      IF(CITEM(1,1).GT..99E30)CALL ERORF(KER,KERR,KGO,MM)
      IF(KNTR1-1)750,710,750
  710 CONTINUE
      PSAT=PSL(TSAT)
      CALL OUTPUT(WT,TTIN,TOUT,CLFAC,VMIN,VMAX,TLMIN,TLMAX,TSAT,Q,
     1CITEM,CNEW,NPAGE,DAY,DPMAX,TLM,DPTOT,PSAT,PS1,PS2,KCOND,
     1KMETL,MN,BWG,
     2TS1,TS2,TLM1,TLM2,UO1,UO2,TR1,TR2,FRAC,FRAC2,TIN2,PSMIN,PSMAX)
  750 CONTINUE
  800 FORMAT(128H1 NP  NT    DTO    TL     TLREQ  VT    UCLN    UO
     1DP        COST    ASTOT      KCOUN  KERR  NSER   SCCT      CST
     2IDN    )
      RETURN
      END
      SUBROUTINE SCDSMP(TSAT,TTIN,TOUT,VT,QOUT,WT,DTO,KMETL,KGAGE,
     1CLFAC,TS1,TS2,PS1,PS2,AZ1,AZ2,Q1,Q2,AREQ,FRAC,PSMAX,PSMIN,
     2TLM,TLM1,TLM2,TR1,TR2,UO1,UO2,TIN2,FRAC2)
C *** THIS S/R IS A DESIGN ROUTINE FOR MULTIPRESSURE CONDENSER
      COMMON IDUM,KGO,IDUM1(4),D1(3),IDUM2,KER,KERR(20),ID1(4),MM,ID2(7)
     1,D2(1218)
      DIMENSION Y(10),TS(10)
      PSAT = PSL(TSAT)
      KODEFR = 0
C *** SET FRAC CONVERGENCE COUNTER
      LFRAC = 0
C *** INITIAL VALUE OF FRAC
      FRAC = 0.5
C *** SET AREQ TO HIGH VALUE SO IT PASSES CHECK AT STATEMENT 590 LATER
      AREQ = 1.E30
C *** SET INCREMENT FOR FRAC
      DELFR = 0.01
C *** FRAC CONVERGENCE LOOP STARTS HERE
   50 LFRAC = LFRAC + 1
      AREQ1 = AREQ
C *** CALC. ZONE ONE HEAT DUTY
      Q1 = FRAC * QOUT
      CALL PPAUT1(TTIN,CP,DEN,TKL,VISL,KODE)
C *** CALC. OUTLET TEMP. FROM ZONE ONE -EQUALS INLET TEMP. TO ZONE TWO
      TOUT1 = Q1/(WT * CP) + TTIN
C *** CALC. OVERALL COEFFICIENT FOR ZONE ONE
      CALL UCOND(VT,UCLN,DTO,TTIN,KMETL,KGAGE,UBASE,FTEMP,FMETL)
      UO1 = CLFAC * UCLN
C *** SET ZONE ONE OUTLET TEMP. EQUAL TO ZONE INLET TEMP.
      TIN2 = TOUT1
      X=TIN2+460.
      DEN2=53.34+4.40127E-2*X-5.1085E-5*X*X
      VT2 = VT * DEN/DEN2
C *** CALC. ZONE TWO OVERALL COEFFICIENT
      CALL UCOND(VT2,UCLN,DTO,TIN2,KMETL,KGAGE,UBASE,FTEMP,FMETL)
      UO2 = CLFAC * UCLN
C *** FIRST GUESS FOR STEAM TEMP. TO ZONE ONE-SET COUNTER FOR
C     NEWTON-RAPHSON CONVERGENCE ROUTINE
      NR = 1
      TS(1)=(TOUT1+TSAT)/2.
C *** MAIN LOOP ON TS1 STARTS HERE
  100 IF(NR-2)130,110,130
  110 IF(Y(1))115,120,120
  115 TS(2)=(TSAT+TS(1))/2.
      GO TO 130
  120 TS(2)=(TOUT1+TS(1))/2.
  130 TS1=TS(NR)
      TITD1 = TS1 - TTIN
      TTD1 = TS1 - TOUT1
      TLM1 =(TOUT1-TTIN)/ALOG(TITD1/TTD1)
```

```
C *** CALC. ZONE ONE SURFACE AREA
      AZ1 = Q1/(TLM1 * UO1)
      PS1 = PSL(TS1)
      PS2 = (2. * PSAT) -PS1
      TS2 = TSL(PS2)
      TITD2 = TS2 - TIN2
      TTD2 = TS2 - TOUT
      TLM2 = (TOUT- TIN2)/ALOG(TITD2/TTD2)
C *** CALC. ZONE TWO SURFACE AREA
      AZ2 = QOUT *(1.0 - FRAC)/(UO2 * TLM2)
      Y(NR) = 1.0 - AZ1/AZ2
C     WRITE(6,1000)TS1,TS2,AZ1,AZ2,Y(NR),NR
      CALL NRCON(NR,TS,Y,KER,28,.01,KODE,10)
      IF(KODE-1)100,160,150
  150 CALL ERORF(KER,KERR,KGO,MM)
  160 CONTINUE
C *** CALC. AREA REQUIRED FOR CONDENSER
      AREQ = AZ1 + AZ2
C *** DONT ALLOW FRAC .LT. .45
      IF(FRAC-.45)700,700,340
C *** FIRST ITERATION IN FRAC LOOP-SKIP THE PRESSURE CHECKS
  340 IF(LFRAC-1)590,590,350
  350 IF(KODEFR-1)400,700,400
  400 IF(PS1 - PSMIN)500,550,550
  500 FRAC = FRAC + DELFR
      KODEFR = 1
      GO TO 50
  550 IF(PS2 - PSMAX)590,590,500
  590 IF(AREQ - AREQ1)600,700,500
  600 FRAC = FRAC - DELFR
      GO TO 50
  700 CONTINUE
      TLM = 0.5*(TLM1 +TLM2)
      TR1 = TIN2 - TTIN
      TR2 = TOUT - TIN2
      FRAC2 = 1.0 - FRAC
C     WRITE(6,900)TS1,TS2,PS1,PS2,AREQ,AZ1,AZ2,FRAC,NR
      RETURN
      END
      SUBROUTINE SCMPR( TSAT,QTOT,WT,CLFAC,KMETL,KGAGE,PSMAX,PSMIN,ASTOT
     1,DTO,GT,GTITD,FRAC,TOUT,TTIN)
      COMMON IDUM,KGO,IDUM1(4),D1(3),IDUM2,KER,KERR(20),ID1(4),MM,ID2(7)
     1,D2(1218)
C *** RATING OF MULTI-PRESSURE CONDENSERS
      DIMENSION T(10),Y(10)
C *** INPUT ITEMS ARE-
C     PSAT - AVG. SATUTATION PRESSURE AT STEAM INLET
C     QTOT - TOTAL HEAT TO BE REJECTED BY SURFACE CONDENSER
C     WT - TOTAL WATER FLOW RATE  LB/HR
C     GT - WATER MASS VELOCITY IN TUBES ,LB/HR-FT2
C     ASTOT - TOTAL OUTSIDE SURFACE AREA ,FT2
      TAV = 0.0
C *** ASURF - SURFACE AREA PER ZONE
      ASURF = ASTOT * 0.5
      PSAT = PSL(TSAT)
      NR = 1
C *** FIRST GUESS
      T(1)=GTITD
C *** MAIN LOOP TO CONV. ON STEAM TEMP.,TS1,STARTS HERE
   90 TTD=T(NR)
      TOUT=TSAT-TTD
      CPAV = 1.0
C *** INITIALIZE COUNTER FOR CONVERGENCE
      LQ = 0
C *** TR - WATER TEMP. RANGE
  100 TR = QTOT/(CPAV * WT)
      LQ = LQ + 1
      TTIN=TOUT-TR
      TAV1 = TAV
C *** CALC. CIRCULATING WATER AVG. TEMP.
      TAV = 0.5 * (TTIN + TOUT)
      X=TAV+460.
      CPAV=1.191328-7.002932E-4*X+6.3408E-7*X*X
C *** CONVERGE ON AVG. HEAT CAPACITY ,CPAV
      IF(ABS(1.-TAV1/TAV)-.001)150,150,120
  120 IF(LQ - 5)100,150,150
  150 TOUT1 =(QTOT * FRAC)/(WT * CPAV) + TTIN
C *** CONVERGE ON CORRECT CP
      X=.5*(TOUT1+TTIN)+460.
      CP1=1.191328-7.002932E-4*X+6.3408E-7*X*X
      IF(ABS(1.-CPAV/CP1)-.004)158,158,155
  155 LQ=LQ+1
      IF(LQ-10)156,158,158
  156 CPAV=CP1
      GO TO 150
  158 CONTINUE
C *** FIRST ZONE RATING
C *** CALC. PERF. OF ZONE ONE - FIND STEAN TEMP.,TS1
      CALL SCRATG(TTIN,WT,UO1,ASURF,    TS1,TOUT1,Q1,GT,PS1,VT,
     1KMETL,KGAGE,CLFAC,DTO,TR1)
C *** SET ZONE ONE OUTLET WATER TEMP. EQUAL TO ZONE TWO INLET
      TIN2 = TOUT1
C *** SECOND ZONE RATING
C *** CALC. PERF. OF ZONE TWO - FIND STEAM TEMP. ,TS2
      CALL SCRATG(TIN2,WT,UO2,ASURF,     TS2,TOUT,Q2,GT,PS2,VT,
     1KMETL,KGAGE,CLFAC,DTO,TR2)
      PSAV = (PS1 + PS2) * 0.5
      Y(NR) =(1.0 - PSAT/PSAV)
C     WRITE(6,1200)TTIN,TOUT,TS1,TS2,NR,Y
      KODE=100
      CALL NRCON(NR,T,Y,KER,29,.007,KODE,10)
      IF(KODE-1)160,200,190
  160 IF(NR-2)180,180,90
  180 T(2)= TTD/(1.-Y(1))
      GO TO 90
  190 CALL ERORF(KER,KERR,KGO,MM)
  200 CONTINUE
      RETURN
      END


      SUBROUTINE SCRATG(TTIN,WT,UO,ASURF,   TSTM,TOUT,QZ,GT,PSTM,VT,
     1KMETL,KGAGE,CLFAC,DTO,TR)
C *** THIS S/R RATES THE PERFORM. OF A ZONE IN MULTI-PRESSURE SURF.
C *** CONDENSER
C *** INPUT ITEMS ARE -
C     TTIN - CIRCULATING WATER INLET TEMP.
C     WATER MASS VELOCITY IN TUBES, LB/HR-FT2
      CALL PPAUT1(TTIN,CPL,DEN,TKL,VISL,KODE)
C *** VELOCITY ENTERING THIS ZONE OF CONDENSER ,FT/SEC
      VT = GT/(3600. * DEN)
C *** CALC. OVERALL CLEAN COEFF. FOR THIS ZONE
      CALL UCOND(VT,UCLN,DTO,TTIN,KMETL,KGAGE,UBASE,FTEMP,FMETL)
      UO = CLFAC * UCLN
C *** CALC. NTU OF THIS ZONE
      XNTU = UO * ASURF/(WT * CPL)
      XK = EXP(XNTU)
      R = 1.0 -(1.0/XK)
C *** CALC. RANGE- TR IN THIS ZONE
      TR = TOUT - TTIN
C *** CALC. ITD IN THIS ZONE
      TITD = TR/R
```

```
C *** CALC. STEAM SAT. TEMP. IN THIS ZONE,TSTM
      TSTM = TTIN + TITD
C *** CALC. STEAM SAT. PRESSURE IN THIS ZONE,PSTM
      PSTM = PSL(TSTM)
      RETURN
      END




      SUBROUTINE SCSBP(DTO,DTI,KMETL,MN,TL,SCCT,CST,COST,NT,PR,KCOND,
     1WTOTL,KERR,ZNS,CSTPB,CPLI)
C *** THIS SUBROUTINE CALCULATES THE SURFACE CONDENSER SHELL BASE PRISE
C *** KMETL - TUBE MATERIAL CODE
C *** NT = NO. OF TUBES
C     DTO = TUBE DIAMETER IN FT.
C     PR = SHELL BASE PRICE,DOLLARS
      DIMENSION FMM(24,6)
      DIMENSION DENN(13),CPL(13)
      DIMENSION KDENA(6)
      DATA DENN/.308,.323,.099,.301,.295,.303,.323,.323,.2833,.280,.290,
     1.290,.163/
      DATA CPL/1.44,1.5,1.0,1.50,3.2,2.21,1.71,2.11,1.47,2.94,2.94.2.94,
     16.62/
      DATA KDENA/6,9,11,12,5,7/
C *** KMETL = CODE NO. OF TUBE MATERIAL
C     1 =ADMIRALTY; 2 =ARSENICAL CU; 3 = AL.; 4 =AL.BRASS; 5 =AL.BRONZE
C     6 =MUNTZ; 7 =90/10 CU-NI; 8 =70/30 CU-NI; 9 =CARBON STEEL;
C     10 =410 S/S; 11 =304 S/S; 12 =316 S/S; 13 =TITANUM
      DATA FMM/0.0,0.0,0.0,0.0,0.0,0.0,0.0.0.0,0.0.0.0,0.0,0.0,0.0,0.0,
     10.0,0.0,0.0,0.0,0.0,0.0,0.0,0.0,0.0.0.0,-.056,-.072,-.088,-.061,
     2-.078,-.095,-.066,-.084,-.102,-.070,-.090,-.110,-.075,-.086.-.117,
     3-.082,-.104,-.126,-.087,-.110,-.133,-.089,-.112,-.136,.009,.009,
     4.009,.010,.010,.010,.011,.011,.011,.012,.012,.012,.013,.013,.013,
     5.014,.014,.014,.015,.015,.015,.016,.016,.016,.054,.059,.064,.061,
     6.066,.071,.067,.072,.077,.072,.077,.082,.079,.083,.087,.088,.092,
     7.096,.094,.097,.100,.101,.104,.107,.117,.147,.177,.130,.167,.204,
     8.143,.183,.223,.153,.196,.239,.170,.213,.256,.190,.233,.276,.206,
     9.250,.294,.216,.267,.311,.069,.081,.093,.077,.091,.105,.086,.099,
     A.112,.092,.106,.120,.101,.114,.127,.113,.127,.141,.122,.136,.150,
     A.130,.144,.158/
      KERR = 0
      FM = 0.0
      PR = 0.0
      PI = 3.141592654
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C *** TUBE SHEET DENSITY,LB/CU.INCH
      KDENTS = KDENA(MN)
      DENTS = DENN(KDENTS)
C *** CALCULATE LENGTH CORRECTION FACTOR TO BE APPLIED TO BASE PRICE
C *** FCL = LENGTH CORRECTION FACTOR
C *** TL = TUBE LENGTH IN FT.
C *** SET MIN. AND MAX. LENGTH FOR COSTING S/R ONLY
      TLMIN = 20.0
      TLMAX = 110.0
      IF(TL - TLMIN)400,32,32
   32 IF(TL - TLMAX)40,40,400
   40 FCL = 0.01544*TL +0.57111
C *** OBTAIN TUBE SHEET MATERIAL FACTOR PER WESTINGHOUSE
C *** NT = NO. OF TUBES
      ZNT = NT
C *** MN = MATERIAL CODE - 1 =MUNTZ; 2=CARBON STEEL; 3=STAINLESS 304;
C *** 4 = STAINLESS 316; 5 = ALUMINUM BRONZE; 6 =90-10 COPPER NICKEL
C *** BASE PRICES INCLUDE MUNTZ METAL TUBE SHEET WITH A THICKNESS EQUAL
C      TO THE TUBE DIAMETER PLUS 1/8IN. THE MATERIAL FACTOR IS TO
C      CHANGE THE STANDARD THICKNESS MUNTZ METAL TUBE SHEET TO A STANDARD
C      THICKNESS TUBE SHEET OF A DIFFERENT MATERIAL.
C *** FM = MATERIAL FACTOR
C *** ADD MULTIPLIER FOR OVER 50000 TUBES-USE 50000 AS BASE AND
C *** INCREASE BY 5( FOR EACH 10000
      FMULT = 1.0
      IF(NT-50000)17,17,16
   17 IF(NT-40000)2,1,1
    1 K = 25
      GO TO 20
    2 IF(NT-30000)4,3,3
    3 K = 22
      GO TO 20
    4 IF(NT-20001)6,5,5
    5 K = 19
      GO TO 20
    6 IF(NT-15001)8,7,7
    7 K = 16
      GO TO 20
    8 IF(NT-12501)10,9,9
    9 K = 13
      GO TO 20
   10 IF(NT-10001)12,11,11
   11 K = 10
      GO TO 20
   12 IF(NT-8001)14,13,13
   13 K = 7
      GO TO 20
   14 K = 4
      GO TO 20
   16 K = 25
```

```
      FMULT = (ZNT-5E4) * 1.05E-4
   20 IF(DTO-0.880)21,21,22
   21 K = K-3
      GO TO 30
   22 IF(DTO-1.125)23,23,24
   23 K = K-2
      GO TO 30
   24 CONTINUE
   25 K = K-1
   30 FM = FMM(K,MN) * FMULT
C *** CALCULATE SHELL BASE PRICE IN DOLLARS -PR
      IF(DTO-0.750)45,45,50
   45 PR = 7.6958333 *ZNT + 97125.0
C     EQUATION GOOD FROM 6000 TO 30000
      GO TO 100
   50 IF(DTO-0.880)55,55,60
   55 PR = 8.794123 *ZNT + 102235.29
C     EQUATION GOOD FROM 6000 TO 40000
      GO TO 100
   60 IF(DTO-1.05)65,65,70
   65 PR = 10.836364 *ZNT + 102181.82
C     EQUATION GOOD FROM 6000 TO 50000
      GO TO 100
   70 IF(DTO-1.13)75,75,80
   75 PR = 12.954545 *ZN[illegible] 103272.73
C     EQUATION GOOD FRO[illegible]000 TO 50000
      GO TO 100
   80 PR = 15.223256 *ZNT + 102237.21
C     EQUATION GOOD FROM 7000 TO 50000
  100 CONTINUE
C     CALCULATE WT./FT.   -WPF LB/FT.
      WPF = (DTO**2-DTI**2)*PI/4.0 *12.0 *DENN(KMETL)
C     DEFINE COST PER LB    -CPLB
C *** CHECK TO SEE IF COST/LB IS GIVEN AS INPUT
C     IF GIVEN CONTINUE OTHERWISE USE CPL ARRAY
C     DEFINE TOTAL COST OF TUBES  -CST
      CSTPB = CPLI
      IF(CPLI-.0001)110,110,120
  110 CSTPB = CPL(KMETL)
  120 CONTINUE
C *** ADD G AND A FACTOR OF 15 PERCENT TO TUBE COST(GENERAL ACCOUNTING)
      CST = 1.15 *(WPF * TL * CSTPB * ZNT)
C *** KCOND - KODE FOR TYPE OF CONDENSER-1=SINGLE PRESSURE,2=MULTI-PRESS
      IF(KCOND - 1)130,130,125
  125 IF(ZNS-1.1)126,126,128
C *** FMF = MULTIPRESSURE CONDENSER FACTOR
C *** ONE CONDENSER
  126 FMF = 0.08
      GO TO 200
C *** TWO CONDENSERS IN SERIES
```

```
  128 FMF = 0.073
      GO TO 200
  130 FMF = 0.0
  200 CONTINUE
C *** HERE WE ADD 0.8 TO THE CORRECTION FACTORS TO ACCOUNT FOR THE
C *** FOLLOWING - WATER BOX TYPE FACTOR
C *** METHOD OF ATTACHMENT FACTOR
C *** WATER BOX DESIGN PRESSURE FACTOR
C *** SHELL AND TUBE SUPPORT ALTERNATE MATERIAL FACTOR
C *** CONDENSATE DEPTH FACTOR
C *** SHELL AND WATER BOX PREPARATION FACTORS
C *** ACCF - ACCESSORIES FACTOR TO ACCOUNT FOR ALL OF THE ABOVE
      ACCF = 0.8
C *** ADD 1.22*PR TO BASE PRICE FOR EXTRAS AND INCLUDE DISCOUNT
C     MULTIPLIER =0.88 OF FEB 1976
C *** SCCT IS COST OF CONDENSER AFTER APPLYING ALL THE FACTORS
      SCCT = 1.22 *(PR *(FM +FCL +FMF +ACCF))
C *** DETERMINE COST OF CONDENSER INSTALLATION
C *** CINSTL = COST OF INSTALLATION
C *** CINSTL IS ASSUMED EQUAL TO 2 * CONDENSER BASE PRICE
      CINSTL = 2.0 * PR
C *** COST = TOTAL COST IN THOUSANDS OF DOLLARS-COMPRISES OF THE
C *** CONDENSER SHELL BASE PRICE(SCCT),COST OF TUBES(CST),AND COST OF
C *** INSTALLATION-CINSTL
      COST = (SCCT + CST + CINSTL)* ZNS/1000.0
C *** CALCULATE TOTAL WEIGHT OF TUBES
      WTUBE = WPF * TL * ZNT
C *** ASSUME TUBE SHEET THICKNESS =DTO+1/8INCH. = DTS
      DTS = DTO + 0.125
C *** ASSUME TUBE SHEET AREA = 5*AREA OF TUBES = ATS
      ATS = 5.0 *ZNT * PI/4.0 * DTO**2
C *** CALCULATE WEIGHT OF TUBE SHEETS
      WTSHT = ATS * DTS * 2.0 * DENTS
C *** WTS =WEIGHT OF TUBE SUPPORTS,ASSUME FACE AREA SAME AS TUBE SHEET
C *** ZNTS= NO.OF TUBE SUPPORTS-ASSUME EVERY 3FT.
      ZNTS = IFIX(TL/3.0-0.5)
C *** THICKNESS OF TUBE SUPPORTS =.625 INCH AND MATERIAL OF CARBON STEEL
      WTS = ZNTS * .625 *ATS * .2833
C *** ESTIMATE TOTAL WEIGHT OF CONDENSER PER SHELL
      WTOTL = 1.50 *(WTUBE+WTSHT+WTS)
      GO TO 800
C *** TUBE LENGTH IS OUTSIDE SPECIFIED LIMITS -SET ERROR CODE -4
  400 KERR = 4
  800 RETURN
      END
      SUBROUTINE SETUP(J,KN,LJ)                                         68130
      COMMON/EPA/TNMIN,TNMAX,TSAT(21),COSTT(21),X(10,21),XC(10),VAMAX,  68140
     1VAMIN,VWMAX,VWMIN,XN,XP,SUBCL,QMIN,QMAX,PITCH,DIA,                68150
     2RNGMX,RNGMN,TLMIN,TLMAX,TITDX,TITDN,TSATA,TSATZ,XHEAT(21)         68160
      COMMON IDUMW(2),KNTRO,IDUM(2),NPAGE,DAY(2),DUMP,IDUM1(34)         68170
      COMMON DUME(171),FALT,DUME2(1046)                                 68180
      COMMON/RAND/SEED,XMODU,XNUM                                       68190
      COMMON/SCOND/TTDMN,TTDMX,TISUM(21)                                68200
C *** SET UP RANDOM NUMBER CONSTANTS                                    68210
      SEED=567.*19.                                                     68220
      XMODU=2.**60+1.                                                   68230
      XNUM=5.**13                                                       68240
      A=0.                                                              68250
      DO 100 I=1,KN                                                     68260
C                                                                       68270
C     SET UP ORIGINAL COMPLEX OF KN POINTS                              68280
   30 X(1,I)=TSATA+RNUM(A)*(TSATZ-TSATA)                                68290
      TSAT(I)=X(1,I)                                                    68300
      CALL QTURB(XHEAT(I),TSAT(I),1.,2)                                 68310
      X(6,I)=TTDMN+RNUM(A)*(TTDMX-TTDMN)                                68320
      SUBCL=X(6,I)                                                      68330
      TINTO=TSAT(I)-SUBCL                                               68340
      TITD=AMIN1(TINTO+50.,TITDX)                                       68350
      IQGO=0                                                            68360
      IRAE=0                                                            68370
      KKILL=0                                                           68380
      NOUE=0                                                            68390
      IUEE=0                                                            68400
C *** CHECK FOR ITD INCONSISTANCIES                                     68410
      IF(TITDN-TITD)11,11,30                                            68420
   11 CONTINUE                                                          68430
      X(2,I)=TITDN+RNUM(A)*(TITD-TITDN)                                 68440
   12 RNG=AMIN1(RNGMX,X(2,I)*.99,TINTO-32.)                             68450
C *** CHECK FOR RANGE INCONSISTANCIES                                   68460
      IF(RNGMN-RNG)36,36,33                                             68470
   33 IQGO=IQGO+1                                                       68480
      IF(IQGO-15)34,34,30                                               68490
C *** INCREASE ITD BY 10 DEGREES                                        68500
   34 X(2,I)=X(2,I)+10.                                                 68510
C *** CHECK THAT ITD WAS NOT INCREASED TOO MUCH                         68520
      IF(X(2,I)-TITD)12,12,30                                           68530
C *** IF RANGE ALREADY HAS A VALUE TRY YO USE IT                        68540
   36 IF(IRAE)38,38,37                                                  68550
   37 IF(X(3,I).GE.RNGMN.AND.X(3,I).LE.RNG)GO TO 39                     68560
   38 IRAE=1                                                            68570
      X(3,I)=RNGMN+RNUM(A)*(RNG-RNGMN)                                  68580
   39 CONTINUE                                                          68590
C                                                                       68600
C     CALCULATE MIN AND MAX TN BY ALLOWING WATER VELOCITY OF 2-10 FPS   68610
C                                                                       68620
```

```
C *** CALCULATE AVERAGE WATER TEMPERATURE AND FIND PHYSICAL PROPERTIES
      TAV=TINTO-X(3,I)/2.
      CALL PPAUT1(TAV,CPW,DENW,D1,D3,KODE)
      TN1=XHEAT(I)*XP/X(3,I)/DIA**2/CPW/DENW/196.35
      TN2=XHEAT(I)*XP/X(3,I)/DIA**2/CPW/DENW/39.27
      TNN=AMAX1(TNMIN,TN1)
      TNX=AMIN1(TNMAX,TN2)
C *** CHECK THAT MIN AND MAX FOR NUMBER OF TUBES IS CONSISTANT
      IF(TNN-TNX)27,27,20
   20 IQGO=IQGO+1
      IF(IQGO.GT.15)GO TO 30
C *** SEE IF MIN NUMBER OF TUBES CAN BE LOWERED BY INCREASING RANGE
      IF(TN1-TNMIN)21,21,25
C *** SEE IF MAX NUMBER OF TUBES CAN BE INCREASED BY DECREASING RANGE
   21 IF(TN2-TNMAX)22,30,30
   22 X(3,I)=X(3,I)-5.
C *** SEE IF RANGE WAS DECREASED TOO MUCH
      IF(X(3,I)-RNGMN)30,39,39
   25 X(3,I)=X(3,I)+5.
C *** SEE IF RANGE WAS INCREASED TOO MUCH
      IF(X(3,I)-RNG)39,39,26
C *** IF MAX RANGE DEPENDED ON ITD THEN INCREASE ITD
   26 IF(RNG-X(2,I))34,34,30
C *** IF NUMBER OF TUBES HAS A VALUE TRY TO USE IT
   27 IF(NOUE)29,29,28
   28 IF(X(5,I).GE.TNN.AND.X(5,I).LE.TNX)GO TO 90
   29 NOUE=1
      X(5,I)=TNN+RNUM(A)*(TNX-TNN)
   90 CONTINUE
C
C     CALCULATE MIN AND MAX TL BY ALLOWING AIR VELOCITY OF 100-1000 FPM
C     AND BY ASSUMING P=.01-1.
C
C *** DETERMINE AIR PHYSICAL PROPERTIES BASED ON AIR INLET TEMPERATURE
      TAV=TINTO-X(2,I)+459.67
      T=TAV-459.67
      DENA=FALT/TAV*39.68863
      CPA=.2401457+2.48709E-7*T+2.990712E-8*T*T
      TL1=XHEAT(I)*XN/X(2,I)/X(5,I)/PITCH/CPA/DENA/5000.
      TL2=XHEAT(I)*XN/X(2,I)/X(5,I)/PITCH/CPA/DENA/5.
      TLN=AMAX1(TLMIN,TL1)
      TLX=AMIN1(TLMAX,TL2)
C *** SEE IF TUBE LENGTH MIN AND MAX IS CONSISTANT
      IF(TLN-TLX)31,31,32
   32 IQGO=IQGO+1
      IF(IQGO.GT.15)GO TO 30
C *** SEE IF MAX TUBE LENGTH CAN BE INCREASED BY DECREASEING NUMBER OF
C *** TUBES
      IF(TL2-TLMAX)91,92,92
   91 X(5,I)=X(5,I)/1.15
```

```
C *** SEE IF NUMBER OF TUBES WAS DECREASED TOO MUCH                     69130
      IF(X(5,I)-TNN)93,90,90                                            69140
   93 IF(KKILL.NE.0)GO TO 30                                            69150
C *** SEE IF MIN NUMBER OF TUBES CAN BE LOWERED BY INCREASING RANGE      69160
      IF(TN1-TNMIN)30,30,25                                             69170
C *** SEE IF MIN TUBE LENGTH CAN BE DECREASED BY INCREASING NUMBER OF   69180
C *** TUBES                                                             69190
   92 IF(TL1-TLMIN)30,30,94                                             69200
   94 X(5,I)=X(5,I)*1.15                                                69210
C *** SEE IF NUMBER OF TUBES WAS INCREASED TOO MUCH                     69220
      IF(X(5,I).LE.TNX)GO TO 90                                         69230
      IF(KKILL.NE.0)GO TO 30                                            69240
C *** SEE IF MAX NUMBER OF TUBES CAN BE INCREASED BY DECREASING RANGE   69250
      IF(TN2-TNMAX)22,30,30                                             69260
C *** IF TUBE LENGTH ALREADY HAS A VALUE TRY TO USE IT                  69270
   31 IF(IUEE)98,98,95                                                  69280
   95 IF(X(4,I).LE.TLX.AND.X(4,I).GE.TLN)GO TO 40                       69290
   98 IUEE=1                                                            69300
      X(4,I)=TLN+RNUM(A)*(TLX-TLN)                                      69310
C                                                                       69320
C     FIND OBJECT FUNCTION                                              69330
C                                                                       69340
   40 CALL COSTER(I,VAIR,VH2O,KKILL)                                    69350
C *** LIMIT THE NUMBER OF OUTPUT PAGES TO 200                           69360
      IF(NPAGE.GE.200) GO TO 200                                        69370
C                                                                       69380
C     SEE IF WATER VELOCITY IS BETWEEN MIN AND MAX FT/SEC.  IF IT IS NOT 69390
C     SET NUMBER OF TUBES SUCH THAT WATER VELOCITY IS ON BOUNDARY.      69400
C                                                                       69410
      IF(KKILL) 75,75,42                                                69420
   42 IQGO=IQGO+1                                                       69430
      IF(IQGO.GT.15)GO TO 30                                            69440
      GO TO (94,91,55,60),KKILL                                         69450
C                                                                       69460
C     SEE IF AIR VELOCITY IS BETWEEN MIN AND MAX FT/MIN                 69470
C     IF IT IS NOT, SET TUBE LENGTH SUCH THAT AIR VELOCITY IS ON        69480
C      BOUNDARY. IF DOING THAT VIOLATES TUBE LENGTH CONSTRAINT,         69490
C     TRY TO CHANGE ITD.                                                69500
C                                                                       69510
   55 X(4,I)=X(4,I)*1.15                                                69520
      IF(X(4,I)-TLX)40,40,56                                            69530
   56 IF(TL2-TLMAX)30,30,57                                             69540
C *** SET TUBE LENGTH TO MAX AND INCREASE ITD                           69550
   57 X(4,I)=TLMAX                                                      69560
      GO TO 34                                                          69570
   60 X(4,I)=X(4,I)/1.15                                                69580
      IF(X(4,I)-TLN)61,40,40                                            69590
   61 IF(TL1-TLMIN)62,30,30                                             69600
   62 X(4,I)=TLMIN                                                      69610
C *** SET TUBE LENGTH TO MIN AND DECREASE ITD                           69620
```

```
      X(2,I)=X(2,I)-10.
      IF(X(2,I)-TITDN)30,12,12
   75 CONTINUE
C
C     SEE IF COST IS HIGHER OR LOWER THAN PREVIOUS COSTS
C
      IF(COSTT(I).LE.COSTT(J)) GO TO 85
      J=I
      GO TO 100
   85 IF(COSTT(I).GE.COSTT(LJ)) GO TO 100
      LJ=I
  100 CONTINUE
  200 CONTINUE
      RETURN
      END
```

```
      SUBROUTINE START
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      CALL SECOND(DAY(2))
      CALL ZEROA
      PI=3.14159
      KGO=1
      KNTR1=0
      KNTRO=0
      NPAGE=1
      NFO=6
      NSUM=0
      RETURN
      END


      SUBROUTINE STORE(NMAX,ITEM,CITEM,CNEW)
      DIMENSION CNEW(15),CITEM(10,15)
C *** THIS S/R LOOKS AT A NEW ARRAY OF ITEMS AND  CHECKS IF THE NEW ARRA
C     SHOULD BE ADDED INTO THE CITEMS MATRIX. THE CITEM MATRIX IS
C     ARRANGED IN ASCENDING ORDER DETERMINED BY CITEM(I,1) SLOT
C *** INPUT VARIABLES ******
C     ITEM - NO. OF ITEMS TO BE STORED FROM CNEW INTO CITEM
C     NMAX - NO.OF STORAGE ITEMS FOR FIRST DIMENSION IN CITEM(NMAX,ITEM)
C     CNEW(NITEM) NEW ARRAY TO BE INTEGRATED INTO CITEM
      DO 100 I=1,NMAX
C     CHECK IF CNEW(1)  IS LOWER THAN CITEM(I,1)
      IF(CNEW(1)-CITEM(I,1))10,100,100
C *** HAVE FOUND THAT CNEW SHOULD BE INTEGRATED INTO THE N SLOT OF CITEM
   10 N = I
      GO TO 200
  100 CONTINUE
C *** AT THIS POINT-THE CNEW(1) IS HIGHER THAN ANY VALUE IN CITEM(I,1)
      GO TO 500
C *** INTEGRATE CNEW INTO CITEM INTO N SLOT
  200 CONTINUE
C *** IF N=NMAX DONT HAVE TO PUSH ANYBODY BACK-JUST GO TO FILL-UP AT 350
      IF(N-NMAX)240,350,500
  240 CONTINUE
C *** FIRST PUSH EVERYONE BACK ONE SLOT
C     SET UP THE VALUE OF K THE FIRST SLOT TO START AT FROM THE BACK
      K=NMAX-N
      DO 300 J = 1,ITEM
      DO 300 I=1,K
C *** START FROM THE LAST SLOT WHEN PUSHING BACK
C     SO THAT NO INFORMATION WILL BE DESTROYED
      L=NMAX-I
      CITEM(L+1,J) = CITEM(L,J)
  300 CONTINUE
C *** NOW INTEGRATE CNEW INTO N SLOT OF CITEM(N,ITEM)
  350 CONTINUE
      DO 400 J = 1,ITEM
      CITEM(N,J) = CNEW(J)
  400 CONTINUE
  500 RETURN
      END


      SUBROUTINE STRUCT(NTT,TUBWT,ZL,DHEDW,RLL,HTSTR,STLAD,ZBUP,ZBPU,
     1CTSTR)
C
C *** THIS SUBROUTINE ESTIMATES THE COST FOR THE STRUCTURE. INCLUDING
C *** GRADING,PAVING,FOUNDATION + STEEL COST.
C
C *** INPUT VARIABLES ***
C     DL    = BUNDLE LENGTH (FT)
C     DHEDW = BUNDLE WIDTH  (INCH)
C     NTT   = TOTAL NUMBER OF TUBES
C     TUBWT = UNIT WEIGHT OF TUBE (LB/FT)
C     RLL   = ROOF LIVE LOAD (LB/FT2)
C     HTSTR = STRUCTURE HEIGHT (FT)
C     STLAD = INDEX FOR STEEL COST ADJUSTMENT
C     ZBUP  = NUMBER OF BUNDLES PER BAY
C     ZBPU  = NUMBER OF BAYS PER UNIT
C
C *** OUTPUT VARIABLE ***
C     CTSTR = STRUCTURE COST ($)
C
C
      ZTT=NTT
      DL=ZL*2.
C
C     THE ONLY DATA AVAILABLE IS FOR WIND LOAD = 35 PSF, SO ASSUME THE
C     WIND LOAD IS NEAR 35 PSF
C
C     CHECK THE WIND MAP FOR ROOF LIVE LOAD. IF LL>20PSF, USE LL=40PSF
C     DATA, IF LL)20PSF, USE LL=12PSF DATA.
C
C     CHECK THE TABLE FOR STEEL PRICE MODIFICATION, INPUT THE ADJUSTMENT
C     INDEX  STLAD
C
C
C     TOTAL WEIGHT OF TUBES
      TTUWT=ZTT*TUBWT*DL
C
C     WEIGHT OF ONE BUNDLE SECTION
```

```
      ACWT1=1.4*TTUWT
C
C     WEIGHT PER UNIT AIR COOLER, NOT INCLUDING STRUCTURE
      ACWT=ACWT1*ZBUP*ZBPU
C
C     PRETEND AS A 45 FT WIDE UNIT, SO THAT THE WEIGHT IN 1000 LB IS
      WT452=ACWT*(45.0*120.0*12.0/DHEDW/DL/ZBUP/ZBPU)/1000.0
      WT456=ACWT*(45.0*160.0*12.0/DHEDW/DL/ZBUP/ZBPU)/1000.0
C
C     DIFFERENT CALCULATIONS FOR DIFFERENT ROOF LIVE LOADS
      IF (RLL-20.0) 10,10,20
C
   10 CONTINUE
C     W*L*H = 45*120*30
      CTWT1=23.047*(WT452-268.0)+33510.0
C     W*L*H = 45*120*50
      CTWT2=23.125*(WT452-268.0)+37650.0
C     W*L*H = 45*160*50
      CTWT3=36.8235*(WT456-358.0)+42240.0
C     W*L*H = 45*160*70
      CTWT4=36.8235*(WT456-358.0)+49190.0
      GO TO 30
C
   20 CONTINUE
      CTWT1=25.625*(WT452-268.0)+37360.0
      CTWT2=26.40625*(WT452-268.0)+41410.0
      CTWT3=37.4705*(WT456-358.0)+49200.0
      CTWT4=36.8235*(WT456-358.0)+56460.0
C
   30 CONTINUE
C
C     INTERPOLATE STRUCTURE HEIGHT
C     W*L = 45*120
      CTHT1=(CTWT2-CTWT1)/20.0*(HTSTR-30.0)+CTWT1
C     W*L = 45*160
      CTHT2=(CTWT4-CTWT3)/20.0*(HTSTR-50.0)+CTWT3
C
C     INTERPOLATE STRUCTURE LENGTH
      IF (DL-120.0) 32,32,34
C
   32 CONTINUE
      CTSTB=(CTHT1-6000.0)/120.0*DL+6000.0
      GO TO 36
C
   34 CONTINUE
      CTSTB=(CTHT2-CTHT1)/40.0*(DL-120.0)+CTHT1
C
   36 CONTINUE
      CTSTB=CTSTB*DHEDW/540.0*ZBUP
C
```

```
C                                                                       71360
C     STEEL COST ADJUSTMENT                                             71370
      ADJUST=0.87*CTSTB*STLAD/100.0                                     71380
      CTSTR=CTSTB+ADJUST                                                71390
C                                                                       71400
      CTSTR=CTSTR*ZBPU/2.                                               71410
C *** ADD 11 PCT. TO INCLUDE GALVANIZING(ADDITIONAL 120 $/TON)          71420
      CTSTR=1.11*CTSTR                                                  71430
      RETURN                                                            71440
      END                                                               71450


      SUBROUTINE SUPER                                                  71460
C *** SUPERVISOR OF CALCULATION PROCEDURE                               71470
      DIMENSION S(20),E(20),KERNO(6)                                    71480
      COMMON NFO,KGO,KNTR0,KNTR1,NSUM,NPAGE,DAY(2),PI                   71490
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP, 71500
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2) 71510
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,    71520
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DIO,DTT,PL,PT             71530
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,     71540
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT, 71550
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8) 71560
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),    71570
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)                     71580
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,  71590
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2), 71600
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,  71610
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA                        71620
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF, 71630
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),  71640
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2), 71650
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)       71660
      COMMON/EPA/TNMIN,TNMAX,TSAT(21),COSTT(21),X(10,21),XC(10),VAMAX,  71670
     1VAMIN,VWMAX,VWMIN,XN,XP,SUBCL,QMIN,QMAX,PITCH,DIA,                71680
     2RNGMX,RNGMN,TLMIN,TLMAX,TITDX,TITDN                               71690
      COMMON/STIN/XLDFT(6),BP(28),HTRTD(28,6),HTRJD(28,6),NLODS,NBKPR   71700
     1,PLOAD,BPMNM(6),TPMNM(6)                                          71710
      COMMON/JUMP/JAKE,TINMX,NO02I,DTN2I,NO01I,NFPIN,NO02O,NO01O        71720
      COMMON/TRACE/SSSUM(9),IISUM(3)                                    71730
      COMMON/BCKPR/BCKMN,BCKMX                                          71740
      COMMON/JAN7/DUM1(18),CONCT                                        71750
      COMMON/SCRAT/CLFAC,KMETL,KGAGE,CITEM(10,15),GTITD                 71760
```

```
C
C     STEEL COST ADJUSTMENT
      ADJUST=0.87*CTSTB*STLAD/100.0
      CTSTR=CTSTB+ADJUST
C
      CTSTR=CTSTR*ZBPU/2.
C *** ADD 11 PCT. TO INCLUDE GALVANIZING(ADDITIONAL 120 $/TON)
      CTSTR=1.11*CTSTR
      RETURN
      END
```

```
      SUBROUTINE SUPER
C *** SUPERVISOR OF CALCULATION PROCEDURE
      DIMENSION S(20),E(20),KERNO(6)
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP,
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2)
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT,
     2Q(2),QDUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8)
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLQ(2)
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2),
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF,
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2),
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)
      COMMON/EPA/TNMIN,TNMAX,TSAT(21),COSTT(21),X(10,21),XC(10),VAMAX,
     1VAMIN,VWMAX,VWMIN,XN,XP,SUBCL,QMIN,QMAX,PITCH,DIA,
     2RNGMX,RNGMN,TLMIN,TLMAX,TITDX,TITDN
      COMMON/STIN/XLDFT(6),BP(28),HTRTD(28,6),HTRJD(28,6),NLODS,NBKPR
     1,PLOAD,BPMNM(6),TPMNM(6)
      COMMON/JUMP/JAKE,TINMX,NOO2I,DTN2I,NOO1I,NFPIN,NOO2O,NOO1O
      COMMON/TRACE/SSSUM(9),IISUM(3)
      COMMON/BCKPR/BCKMN,BCKMX
      COMMON/JAN7/DUM1(18),CONCT
      COMMON/SCRAT/CLFAC,KMETL,KGAGE,CITEM(10,15),GTITD
```

```
C *** ENTER ERROR NO. IN DATA STATEMENT WHICH ARE NOT PERMANENT
      DATA KERNO/64,62,70,71,98,79/
      TOL=.005
      LSUP1=0
      CALL EXINI
      IF (KGO-1) 10,10,500
   10 CALL GEOM1
   30 LSUP=1
      IF(KCI-2)36,80,120
C *** SET UP PARAMETERS TO GUESS TIN(1)
C *** MAKE THE FIRST GUESS FOR ITD SLIGHTLY HIGHER THAN THE DESIGN ITD
   36 S(1)=57./SSSUM(9)
      ZTIN2=TCONV(TIN(2),1,2)
C *** GIVEN THE SATURATION TEMPERATURE, QTURB FINDS THE
C *** HEAT REJECT OF THE TURBINE.
   38 TTT=ZTIN2+60./S(LSUP)
      IF(TTT-250.)40,39,39
   39 TTT=250.
      S(LSUP)=60./(250.-ZTIN2)
   40 CONTINUE
C *** IF TTT CONVERGES ABOVE TINMX THEN SUBROUTINE COSTER SHOULD
C *** CHECK AND ADJUST PLOAD
      CALL QTURB(QREJ,TTT,PLOAD,2)
      QD(1)=QREJ
C *** SET MM=0 IN CASE PREVIOUS ITERATION HAD KER=23 FROM QTURB. THIS
C *** WILL ALSO DELETE RECORD OF SOME ERRORS IN QBALN FROM LAST  TIME
      MM=0
C *** IF CONCT IS ZERO THEN ASSUME A SURFACE CONDENSER IS USED
      IF(CONCT-.001)44,44,46
   44 CALL SCMPR(TTT,QREJ,W(1),CLFAC,KMETL,KGAGE,BCKMX,BCKMN,
     1CITEM(1,11),CITEM(1,4),CITEM(1,13),GTITD,CITEM(1,15),TIN(1),
     2TOUT(1))
      SUBCL=TTT-TIN(1)
      GTITD=SUBCL
      TD=TIN(1)-ZTIN2
      TIN(1)=TIN(1)+459.67
      TOUT(1)=TOUT(1)+459.67
      TT(1)=TIN(1)
      GO TO 120
C *** FOR JET COND. ASSUME TTD IS PROPORTIONAL TO Q
   46 SUBCL=QREJ*X(6,NSUM)/SSUM(8,NSUM)/1.E06
      TIN(1)=TTT-SUBCL
      TIN(1)=TCONV(TIN(1),1,1)
C *** THE ITD IS CONSTANTLY CHANGING. TD MUST BE SET FOR USE
      TD=TIN(1)-TIN(2)
      TT(1)=TIN(1)
C *** CONVERGE ON CORRECT CP
      LQ=1
      CPX=1.
   45 TOUT(1)=TIN(1)-QREJ/W(1)/CPX
```

```
      XX=.5*(TIN(1)+TOUT(1))
      CP1=OCL(1)+OCL(2)*XX+OCL(3)*XX*XX
      IF(ABS(1.-CP1/CPX)-.004)48,48,47
   47 IF(LQ-5)49,48,48
   49 LQ=LQ+1
      CPX=CP1
      GO TO 45
   48 CONTINUE
      GO TO 120
   80 IF (VAPPI-.1)     90,90,100
   90 S(1)=1.
C *** IN FAN CONTROL MAKE GUESS FOR VAPP SLIGHTLY LOWER THAN DESIGN VAPP
      IF(JAKE.EQ.3)S(1)=721./SSUM(10,NSUM)
      GO TO 110
  100 S(1)=650./VAPP
  110 IF(S(LSUP)-.350)112,112,115
  112 KER=11
      CALL ERORF(KER,KERR,KGO,MM)
      GO TO 500
  115 VAPP=650./S(LSUP)
  120 CALL QBALN
  123 IF(KER) 124,124,193
  124 GAMAX=VAPP /RAPMX*4.5
C *** CALCULATE AIRSIDE HEAT TRANSFER COEFFICIENT
      CALL HTAIR(GAMAX,DFR,VIS(2),REA(2),TK(2),PRAN(2),HAIR,CFH,CFR,
     1RARAF,FINEF,RFIN)
      HAIRD=HAIR
      RFIND=RFIN
      CALL EXCON
  185 IF (KGO-2) 187,500,187
  187 IF(KER) 210,210,193
C *** CHECK HERE FOR ERRORS FOUND IN QBALN,PPROP, AND MTDOV CAUSED BY
C *   POOR GUESS FROM SUPER
  193 DO 194 I=1,6
      IF (KER-KERNO(I)) 194,195,194
  194 CONTINUE
      GO TO 200
  195 IF (LSUP-1)  196,196,197
  196 S(1)=S(1)*.5
      GO TO 198
  197 S(LSUP)=(S(LSUP)+S(LSUP-1))*.5
  198 LSUP1=LSUP1+1
      IF (LSUP1-20)199,200,200
  199 KER=0
      GO TO 240
  200 CALL ERORF (KER,KERR,KGO,MM)
      GO TO 500
  210 E(LSUP)=FSUM-1.
      LSUP1=0
      IF(LSUP-2)228,230,230
```

```
C *** SIMPLE ITERATION USED FOR SECOND QUESS
  228 S(2)=S(1)/FSUM
  230 CONTINUE
      CALL NRCON(LSUP,S,E,KER,50,TOL,K,20)
      IF(K-1) 240,250,234
  234 CALL ERORF(KER,KERR,KGO,MM)
      GO TO 500
  240 IF(KCI-2)38,110,120
C *** END OF SUPER HEAT TRANSFER LOOP
C *** CALCULATE PRESSURE DROPS
C *** IF KKILL IS TO BE SET IN COSTER  THEN DO NOT CALL DPAIR OR DPTUB
  250 IF(JAKE.EQ.3)GO TO 260
C *** FOR INITIAL COMPLEX DO NOT LET VAPP GO ABOVE 1000 FPM
      IF(IISUM(1).GT.0)GO TO 251
      IF(VAPP-1010.)251,251,500
  251 CONTINUE
      IF(VAPP-(VAMAX+.01))255,255,500
  255 IF(VAPP-(VAMIN-.01))500,260,260
  260 CALL DPAIR
      HAIR =HAIRD
      RFIN =RFIND
  270 CALL DPTUB
  500 CONTINUE
 2000 RETURN
      END
```

```
      FUNCTION TCONV(T,KUNIT,KDIR)
C *** TCONV CONVERTS TEMPERATURES TO ABSOLUTE AND VICEVERSA
C *** KUNIT=1 - U.S. UNITS , KUNIT=2 - S.I. UNITS
C *** KDIR=1 - TO ABSOLUTE , KDIR=2 - FROM ABSOLUTE
C *** IF THE TEMPERATURE IS ZERO (=0.0), IT REMAINS ZERO
      TCONV=0.0
      IF (ABS(T)-1.0E-6) 100,10,10
   10 KGO=2*KUNIT-2+KDIR
      GO TO (20,30,40,50) , KGO
   20 TCONV=T+459.67
      GO TO 100
   30 TCONV=T-459.67
      GO TO 100
   40 TCONV=(T+273.15)*1.8
      GO TO 100
   50 TCONV=T/1.8-273.15
```

```
  100 RETURN                                                            73180
      END                                                               73190


      SUBROUTINE TRANS(NMOT,HPMOT,CTRAN,TRANC)                          73200
C                                                                       73210
C *** THIS PROGRAM CALCULATE THE COST FOR POWER TRANSMISSION            73220
C                                                                       73230
C *** INPUT VARIABLE ***                                                73240
C     HPMOT = MOTOR HORSEPOWER                                          73250
C                                                                       73260
C *** OUTPUT VARIABLE ***                                               73270
C     CTRAN = COST FOR ONE TRANSMISSION ($)                             73280
C                                                                       73290
      ZMOT=NMOT                                                         73300
C     MOTOR HORSEPOWER ON7.5 ,USE DIRECT MOTOR DRIVE                    73310
C                      7.5N20.0 USE V-BELT                              73320
C                      20.ON   USE GEARBOX                              73330
C                                                                       73340
      IF (HPMOT-7.5) 10,10,20                                           73350
   10 CONTINUE                                                          73360
C     DIRECT MOTOR DRIVE                                                73370
C     THE COST IS SMALL.  NEGLECT.                                      73380
      CTRAN=0.0                                                         73390
      GO TO 300                                                         73400
C                                                                       73410
   20 CONTINUE                                                          73420
      IF (HPMOT-20.0) 30,30,40                                          73430
   30 CONTINUE                                                          73440
C     V-BELT DRIVE                                                      73450
C     DATA NOT AVAILABLE NOW. USE THE EXTRAPOLATION OF GEAR BOX         73460
C                                                                       73470
   40 CONTINUE                                                          73480
C     GEARBOX DRIVE                                                     73490
C                                                                       73500
      INDEX=INT(HPMOT)/25+1                                             73510
      IF(INDEX.GT.8)GO TO 250                                           73520
      GO TO (25,50,75,100,125,150,175,200) INDEX                        73530
   25 CTRAN=41.6*HPMOT                                                  73540
      GO TO 300                                                         73550
   50 CTRAN=47.6*(HPMOT-25.0)+1040.0                                    73560
      GO TO 300                                                         73570
   75 CTRAN=66.8*(HPMOT-50.0)+2230.0                                    73580
```

```
      GO TO 300
  100 CTRAN=64.0*(HPMOT-75.0)+3900.0
      GO TO 300
  125 CTRAN=33.6*(HPMOT-100.0)+5500.0
      GO TO 300
  150 CTRAN=22.4*(HPMOT-125.0)+6340.0
      GO TO 300
  175 CTRAN=12.*(HPMOT-150.)+6900.
      GO TO 300
  200 CTRAN=12.*(HPMOT-175.)+7200.
      GO TO 300
  250 CTRAN=12.*(HPMOT-200.)+7500.
C
  300 CONTINUE
      TRANC=ZMOT*CTRAN
C *** ADD 10 PCT. FOR SHIPPING TO MANUFACTURER
      TRANC=1.1*TRANC
C
C
      RETURN
      END
```

```
      FUNCTION TSL(PP)
C
C     FROM PP IN INCHES OF MERCURY, FIND THE SATURATION TEMPERATURE IN
C     DEGREES F. TAKEN FROM PAGE 44 OF *CALCULATIONS OF PROPERTIES OF
C     STEAM* BY MCCLINTOCK AND SILVESTRI
C
      DIMENSION B(6),T(6)
      DATA B/1.52264683,-.682309518,.164114952,-2.02321649E-03,
     1-1.92391111E-03,-5.74549419E-04/
C *** DO NOT ALLOW PP TO GO ABOVE THE CRITICAL POINT OR
C *** BELOW THE FREEZING POINT
      IF(PP.LT..2)PP=.2
      IF(PP.GT.6530.)PP=6530.
      T(1)=1.
      P=PP/2.036
      T(2)=(ALOG(3529.05823/P)**0.4-1.48047125)/(-1.089944)
      Y=2.*T(2)
      W=B(1)+T(2)*B(2)
      DO 2 N=3,6
      T(N)=Y*T(N-1)-T(N-2)
```

```
    2 W=W+T(N)*B(N)                                                     74000
      TSL=1.8*(647.3/W-273.15)+32.                                      74010
      RETURN                                                            74020
      END                                                               74030


      SUBROUTINE TUBEF(KTUBE,KFIN,NFPIN,DTO,DLTTK,DFH,DFT,WTUBE,WFIN,WTU 74040
     1BF,ATUBE,BFIN,CTUB1,CTUB,CFIN)                                     74050
C                                                                       74060
C *** THIS SUBROUTINE CALCULATES THE COST OF TUBE AND FIN IN $/FT       74070
C                                                                       74080
      DATA DENCS,DENAL/.2833,.0975/                                     74090
C *** DENSITY OF CARBON STEEL IS 0.2833 LB/IN3                          74100
C *** DENSITY OF ALUMIMUN STRIP IS 0.0975 LB/IN3                        74110
C                                                                       74120
C *** INPUT VARIABLES ***                                               74130
C     KTUBE = TUBE CODE.   0 FOR WELDED TUBE                            74140
C                          1 FOR SEAMLESS TUBE                          74150
C     KFIN  = FIN CODE.    0 FOR L-FINNED TUBE                          74160
C                          1 FOR G-FINNED TUBE                          74170
C                          2 FOR EXTRUDED -FIN TUBE                     74180
C     NFPIN = NUMBER OF FINS PER INCH                                   74190
C     DTO   = TUBE OUTSIDE DIAMETER (INCH)                              74200
C     DLTTK = TUBE WALL THICKNESS (INCH)                                74210
C     DFH   = FIN HEIGHT (INCH)                                         74220
C     DFT   = FIN THICKNESS (INCH)                                      74230
C                                                                       74240
C *** OUTPUT VARIABLES ***                                              74250
C                                                                       74260
C     WTUBE = CARBON STEEL TUBE WEIGHT (LB/FT)                          74270
C     WFIN  = ALUMIMUN FIN STRIP WEIGHT (LB/FT)                         74280
C     WTUBF = TUBE AND FIN WEIGHT (LB/FT)                               74290
C     CTUB1 = COST FOR TUBE AND FIN PER UNIT LENGTH ($/FT)              74300
C                                                                       74310
C                                                                       74320
C *** INTERNAL VARIABLES ***                                            74330
C                                                                       74340
C     DENCS = CARBON STEEL DENSITY (LB/IN3)                             74350
C     DENAL = ALUMINUM DENSITY (LB/IN3)                                 74360
C     CFIN  = COST FOR ALUMIMUN FIN STRIP ($/LB)                        74370
C     CTUB  = COST FOR CARBON STEEL TUBE ($/LB)                         74380
C     FOVHD = OVERHEAD FACTOR FOR TUBE AND FIN                          74390
C     DSLEV = FIN SLEEVE THICKNESS (INCH)                               74400
```

```
C
C
      ZFPIN=NFPIN
      IF (KFIN-1) 5,6,7
C
C --- L-FINNED TUBE
    5 DSLEV=DFT
      FOVHD=1.0
      GO TO 8
C
C --- G-FINNED TUBE
    6 DSLEV=0.0
      FOVHD=1.2
      GO TO 8
C
C --- EXTRUDED FIN TUBE
    7 DSLEV=0.0
      FOVHD=1.4
C
    8 CONTINUE
C
      DTI=DTO-2.0*DLTTK
      DFR=DTO+2.0*DSLEV
      DOF=DFR+2.0*DFH
C
C     CARBON STEEL TUBE WEIGHT PER FOOT (LB)
      WTUBE=3.1416/4.0*(DTO**2-DTI**2)*12.0*DENCS
C
C     ALUMIMUN FIN STRIP WEIGHT PER FOOT (LB)
      WFIN=(3.1416/4.0*(DOF**2-DFR**2)*DFT*ZFPIN*12.0+3.1416/4.0*(DFR**2
     1      -DTO**2)*12.0)    *DENAL
C
      WTUBF=WTUBE+WFIN
C
C
      IF (KTUBE-1) 10,20,20
C
C *** SA-214  WELDED TUBE..........PRICE AS OF APRIL, 1976
   10 CTUB=0.7008
      GO TO 30
C
C *** SA-179  SEAMLESS TUBE........PRICE AS OF APRIL, 1976
   20 CTUB=1.376
C
   30 CONTINUE
C
C     TUBE COST
      ATUBE=WTUBE*CTUB
C     FIN COST
      BFIN=WFIN*CFIN
```

```
C
C     COST/FT = ( WFIN*CFIN + WTUBE*CTUBE ) * FOVHD
      CTUB1=(WFIN*CFIN+WTUBE*CTUB) * FOVHD
C *** MARK-UP FACTOR IS NOT USED HERE, BUT WILL BE USED LATER
C
      RETURN
      END


      SUBROUTINE UCOND(VT,UCLN,DTO,TTIN,KMETL,KGAGE,UBASE,FTEMP,FMETL)
      DIMENSION AMETL(7,13)
C *** FOLLOWING VARIABLES ARE INPUT
C *** VT = TUBE SIDE VELOCITY FT/SEC.
C *** DTO = TUBE OD INCH.
C *** TTIN = TUBE SIDE WATER INLET TEMP. DEG.F
C *** KMETL = CODE NO. OF METAL -NO.1 TO 13
C *** KGAGE = GAGE NO. OF METAL -NO.1 TO 7
C *** FOLLOWING VARIABLES ARE OUTPUT
C *** UCLN = OVERALL HT. COEF. FOR NEW CLEAN TUBES CORRECTED FOR VARIOUS
C *** MATERIALS, GAUGES AND INLET WATER TEMPERATURES.
C *** UBASE = HT. COEF. BASED ON C*SQRT(VT) AND ON NEW CLEAN TUBES
C *** FTEMP = CORECTION FACTOR FOR INLET WATER TEMP.
C *** FMETL = CORRECTION FACTOR FOR METAL AND GAUGE
C *** CALC. OVERALL CONDENSING COEF. FOR SURFACE CONDENSERS USING HEI
C *** METHODS -6TH EDITION -1970
C *** FOLLOWING IS TABLE ST-1 PAGE 4 OF HEI, REF. IBID,TUBE METAL
C *** CORRECTION TO CLEAN COEF.
      DATA AMETL/1.06,1.04,1.02,1.0,.96,.92,.87,
     1           1.06,1.04,1.02,1.0,.96,.92,.87,
     2           1.06,1.04,1.02,1.0,.96,.92,.87,
     3           1.03,1.02,1.00,.97,.94,.90,.84,
     4           1.03,1.02,1.00,.97,.94,.90,.84,
     5           1.03,1.02,1.00,.97,.94,.90,.84,
     6           0.99,0.97,0.94,.90,.85,.80,.74,
     7           0.93,0.90,0.87,.82,.77,.71,.64,
     8           1.00,0.98,0.95,.91,.86,.80,.74,
     9           0.88,0.85,0.82,.76,.70,.65,.59,
     A           0.83,0.79,0.75,.69,.63,.56,.49,
     B           0.78,0.76,0.74,.69,.65,.60,.54,
     C           0.85,0.81,0.77,.71,.65,.56,.50/
C             KGAGE   BWG   DTTH
C               1      24   .022
C               2      22   .028
```

```
C               3      20   .035
C               4      18   .049
C               5      16   .065
C               6      14   .083
C               7      12   .109
C *** FIRST CALCULATE UBASE HT. COEF. FOR SURFACE COND. USING ABOVE
C *** METHODS FIG. SF-2 PAGE 5
      IF(DTO-.80)110,110,120
C *** CONSTANT FOR 5/8 AND 3/4 IN. OD TUBES
  110 C = 267.
      GO TO 150
  120 IF(DTO-1.1)130,130,140
C *** CONSTANT FOR 7/8 AND 1.0 IN. OD TUBES
  130 C = 263.
      GO TO 150
C *** CONSTANT FOR 1 1/8 AND 1 1/4 IN. OD TUBES
  140 C = 259.
      GO TO 150
  150 UBASE = C * SQRT(VT)
C *** CALC. TEMP. CORRECTION FACTOR USING ABOVE METHODS
C *** BELOW IS A CURVE FIT OF FIG. SF-2 PAGE 5 OF ABOVE
      IF(TTIN-50.)210,210,220
  210 FTEMP = TTIN * .013 + .16
      FTEMP=AMAX1(.576,FTEMP)
      GO TO 270
  220 IF(TTIN-70.)230,230,240
  230 FTEMP = TTIN * .0095 + .335
      GO TO 270
  240 IF(TTIN-100.)250,250,260
  250 FTEMP = TTIN * .00333 + .7669
      GO TO 270
  260 FTEMP = 0.002*TTIN + 0.9
  270 CONTINUE
C *** LOOK-UP OF TUBE METAL CORRECTION FACTOR FROM TABLE ST-1 PAGE 4
C *** OF ABOVE
      FMETL = AMETL(KGAGE,KMETL)
      UCLN = UBASE * FTEMP * FMETL
      RETURN
      END
      SUBROUTINE UOSEN(KCLG)                                            75710
C *** CALC. OVERALL SENSIBLE HEAT TRANSFER AND PRESSURE DROP             75720
      COMMON NFO,KGO,KNTRO,KNTR1,NSUM,NPAGE,DAY(2),PI                   75730
      COMMON KCI,KER,KERR(20),KFIN,KREG,LAIC,LSUP,MM,NP,NR,NT1,NT2,NTP, 75740
     1NTR,NTT,ABARE,AFAN,AMIN,APLOT,APPR,ASBUN,ASTOT,AXAV,AXPP(20),CP(2) 75750
     2,DEN(2),DEN12(2,2),DENFN,DENLZ(7),DBW,DEQ,DFH,DFR,DFS,DFT,DKL,    75760
     3DLSP,DLTE,DLTO,DLTS,DNZ(2),DTI,DTIM,DTF,DTO,DTT,PL,PT             75770
      COMMON DPAD,DPAF,DPAM,DPAW,DPF(10),DPI,DPNZ(2),DPT,DPTA,DPTF,     75780
     1DPTOT(2),POUT(2),PTUB,RV2,GAMAX,GT,HPFNC,HAIR,HTS,UBARE,UCLN,UTOT, 75790
     2Q(2),QOUT,QTOT,RFI,RFIN,RFTOT,RTOT,RTW,TAV(2),TIN(2),TOUT(2),TT(8) 75800
     3,TWALL,TD,TW,TMTD,TK(2),VAPP,VNZ(2),VT,DFAN,TLTE,AOF,VISLZ(7),    75810
     4VIS(2),VIS12(2,2),VISW,W(2),WAPF,WB(2),WLO(2)                     75820
      COMMON ANG(3),CFH(3),CFP(3),CFR,CKBSC,CKFNG,CKHSC,CKLOV,CKSTC,F,  75830
     1FALT,FINEF,FFF,FSUM,OCL(4),ODL(4),OKL(4),OML(4),OMV(4),P,PRAN(2), 75840
     2PRALZ(7),R,RAOI,RAOR,RARAF,RAPMX,REA(2),RE12(2,2),RFNPL,RPT,TLA,  75850
     3XREX,ZMP,ZNF,ZNTP,ZNTR,ZNTT,ZTPP(20),ZTPPA                        75860
      COMMON ZTRD,ANGI,ZBYP,ZBUP,ZBUS,ZFAN,DFANI,DLOV,ZNFI,PTI,TKT,TKF, 75870
     1WD(2),VAPPI,TAMB,HALT,C319,TIND(2),TOUTD(2),RFD,PSD,TTMIN,QD(7),  75880
     2CARD7(6),DNZI(2),PDI,CFNG,CHSC,CLOV,CBSC,PRSTC,RFAIR,RFCT,ZNOZ(2), 75890
     3RASPC,ZTPD,ZNTD,COST(7),SSUM(16,30),ISUM(13,30),PRICE(2,21)       75900
      REA(1)=GT *DTI/(29.0*VIS(1))                                      75910
      HTS=.058*REA(1)**.7*PRAN(1)**.5*TK(1)*12.0/DTI                    75920
   80 UTOT =1.0/(1.0/HAIR+RAOI/HTS +RTOT+RFIN)                          75930
  200 CONTINUE                                                          75940
  500 RETURN                                                            75950
      END                                                               75960
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      SUBROUTINE ZEROA                                                  75970
      COMMON IDUMP(6),DUMP(3),IDUMW(34),DUMW(246),DUM(972)              75980
      DO 10 I=1,34                                                      75990
   10 IDUMW(I)=0                                                        76000
      DO 20 I=1,246                                                     76010
   20 DUMW(I)=0.0                                                       76020
      DO 30 I=1,60                                                      76030
   30 DUM(I)=0.0                                                        76040
      RETURN                                                            76050
      END                                                               76060
```